PB80-213036

Review of New Source Performance Standards for Coal-Fired Utility Boilers, Phase Three Report Sensitivity Studies for the Selection of a Revised Standard

Teknekron, Inc.
Berkeley, CA

Prepared for

Environmental Protection Agency
Washington, DC

Jun 79

U.S. Department of Commerce
National Technical Information Service
NTIS

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA 600/7-79-215	2.	3. RECIPIENT'S ACCESSION NO. PB80 213036
4. TITLE AND SUBTITLE Review of New Source Performance Standards for Coal Fired Utility Boilers, Phase Three Report		5. REPORT DATE June 1979 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Van Horn, A.J., G.C. Ferrell, R.M. Brandi, R.A. Chapman		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Energy and Environmental Engineering Division Teknekron, Inc. 2118 Milvia Street Berkeley, California 94704		10. PROGRAM ELEMENT NO. 1NE 827 11. CONTRACT/GRANT NO. 68-01-3092
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Office of Environmental Engineering & Technology Office of Research and Development Washington, DC 20460		13. TYPE OF REPORT AND PERIOD COVERED 14. SPONSORING AGENCY CODE EPA/ORD/17

15. SUPPLEMENTARY NOTES

This project is part of the EPA-planned and coordinated Federal Interagency Energy/Environment R&D Program.

16. ABSTRACT

This report summarizes Teknekron's Phase 3 study of the projected effects of several different potential revisions to the current New Source Performance Standards (NSPS) for sulfur dioxide (SO_2) emissions from coal-fired electric utility boilers. The revised NSPS (RNSPS) is assumed to apply to all coal-fired units with a generating capacity of 25 megawatts or more, beginning operation after 1982. A principal purpose of this phase of the RNSPS analysis is to present to decision makers the critical uncertainties that will influence utility costs, coal choices, and pollution control measures adopted by utilities in response to alternative standards. Answers are presented to the following generic questions (which are broken down into highly specific questions in the report):

1. How will utility choices be affected by different standards and uncertainties in key factors?
2. How well can the impacts of various full and partial scrubbing options be distinguished?
3. What are the likely energy, economic, environmental, and resource impacts of a revised NSPS?

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Earth Atmosphere Combustion Energy Conversion	Energy Cycle: Energy Conversion Fuel: Coal	6F 8F 10A 10B 7B 13B 97A 97F 97G

18. DISTRIBUTION STATEMENT Release to public	19. SECURITY CLASS *(This Report)* unclassified	21. NO. OF PAGES
	20. SECURITY CLASS *(This page)* unclassified	22. PRICE

EPA Form 2220-1 (9-73)

*U.S. GOVERNMENT PRINTING OFFICE: 1980 311-132/60 1-3

United States
Environmental Protection
Agency

Office of Environmental Engineering
and Technology
Washington DC 20460

EPA-600/7-79-215
December 1979

PB80-213036

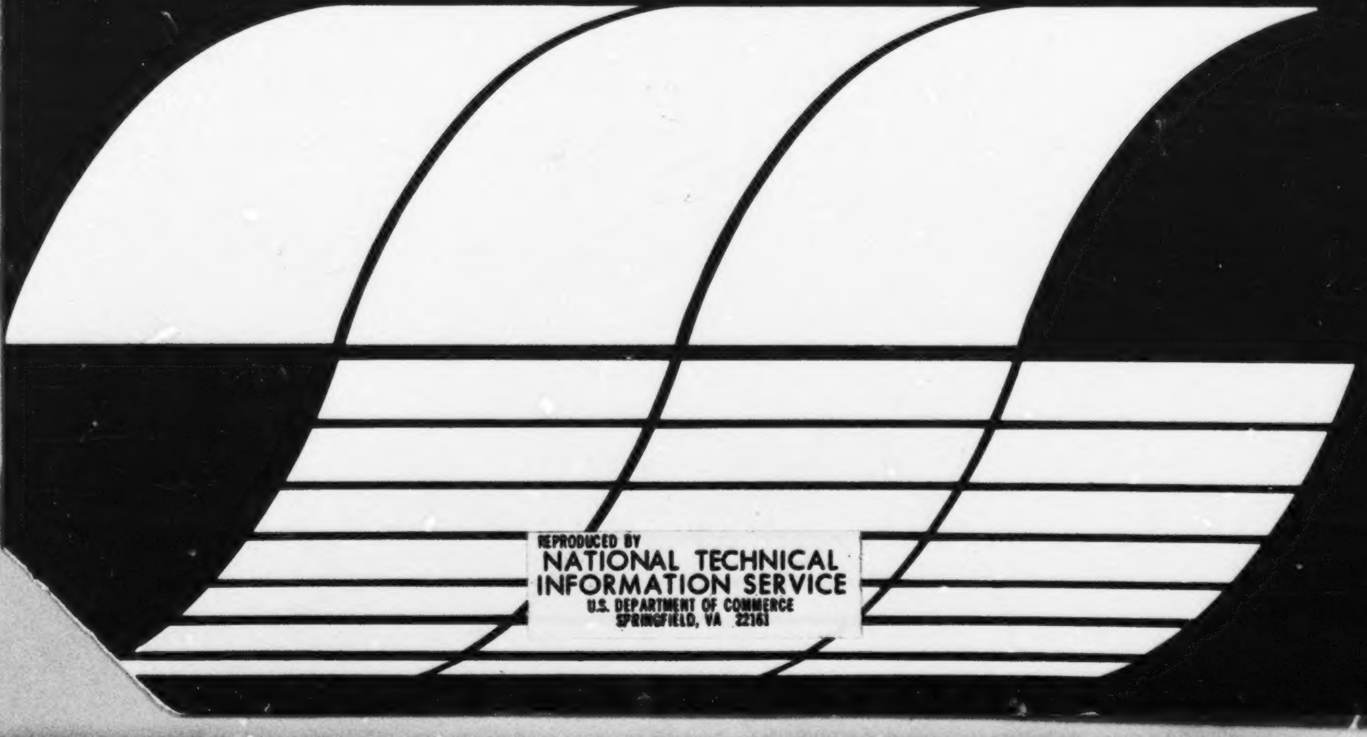
Research and Development

EPA

Review of New Source Performance Standards for Coal Fired Utility Boilers

Phase Three Report

Interagency Energy/Environment R&D Program Report



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EPA-600/7-79-215
December 1979

REVIEW OF NEW SOURCE PERFORMANCE STANDARDS FOR COAL-FIRED UTILITY BOILERS

PHASE 3 FINAL REPORT
SENSITIVITY STUDIES FOR THE SELECTION OF A REVISED STANDARD

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WASHINGTON, D.C. 20460

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FOREWORD

Critical uncertainties surround a number of key factors that will influence the future impacts of the revised New Source Performance Standards (RNSPS) to be established for coal-fired electric utility boilers. These factors will affect utility costs and hence will influence the coal choices and pollution control measures adopted by utilities in response to alternative standards. For the study reported herein, city-specific analyses were carried out to examine utility coal and pollution control choices and their sensitivity to the factors of interest. Complementing these sensitivity analyses are state, regional, and national impact projections from the Utility Simulation Model for alternative standards for the period from 1976 to the year 2000. Together, these analyses and impact projections constitute Phase 3 of Teknekron's RNSPS review. The results of Phases 1 and 2 are presented elsewhere.[1,2,3]

The sensitivity studies provide answers to the following generic questions (which are broken down into highly specific questions in the body of this report):

1. How will utility choices be affected by different standards and by uncertainties in key factors?
2. How well can the impacts of various full and partial scrubbing options be distinguished?
3. What are the likely impacts of a revised NSPS?

Key elements that were varied include coal mine prices, coal transportation rates, coal sulfur and Btu contents, and the costs and performance of FGD scrubbers. In each case, the selected range of variation reflects the element's degree of uncertainty and sensitivity to critical issues. For example, physical parameters such as coal sulfur content and heating values for a specific coal seam are taken from data on likely reserves with their associated variations; while the range of uncertainty surrounding f.o.b. mine prices and transportation costs reflects projected market conditions. For the costs of flue gas desulfurization (FGD), use was made of engineering estimates developed independently by PEDCo and by the Tennessee Valley Authority; the TVA capital and operating costs used in this sensitivity study are significantly lower than PEDCo's.[4,5,6] (See Appendix A.) The report discusses effects of these variations on the ability to distinguish analytically between similar standards. Also discussed are the sensitivities of several cost-effectiveness calculations (for example, cost per ton of SO_2 removed) which have been posited as measures of the worth of various standards.

The impacts of revised standards will depend not only on utility coal and pollution control choices but also on such factors as the future growth in electricity demand, the amount of nuclear capacity, the phasing out of gas steam plants, and the price of oil. These factors are themselves subject to uncertainty. The latest assumptions of the joint EPA/DOE working group[7] were used in the projections for 1976 to 2000 (see Appendix G).

This report focuses on full versus partial scrubbing, considering several forms of the revised standard; on coal properties and supply characteristics; on FGD design, costs, and performance; on city-specific sensitivity studies; and on the Utility Simulation Model's yearly projections of regional and national impacts from 1976 to the year 2000. Potential RNSPS analyzed here include the EPA's September 1978 proposed full scrubbing standard and several alternative standards that would permit partial scrubbing. Appendix I, added in June 1979, presents a brief comparison of the final promulgated RNSPS announced on May 25, 1979, and two of the options described in this report.

ABSTRACT

This report summarizes Teknekron's Phase 3 study of the projected effects of several different potential revisions to the current New Source Performance Standard (NSPS) for sulfur dioxide (SO_2) emissions from coal-fired electric utility boilers. The revised NSPS (RNSPS) is assumed to apply to all coal-fired units with a generating capacity of 25 megawatts or more, beginning operation after 1982. A principal purpose of this phase of the RNSPS analysis is to present to decision makers the critical uncertainties that will influence utility costs, coal choices, and pollution control measures adopted by utilities in response to alternative standards. Answers are presented to the following generic questions (which are broken down into highly specific questions in the report):

1. How will utility choices be affected by different standards and uncertainties in key factors?
2. How well can the impacts of various full and partial scrubbing options be distinguished?
3. What are the likely energy, economic, environmental, and resource impacts of a revised NSPS?

This report focuses on issues of full versus partial scrubbing, considering several forms of the revised standard; on coal properties and supply characteristics; on FGD design, costs, and performance; on city-specific sensitivity studies; and on the Utility Simulation Model's yearly projections of regional and national impacts from 1976 to the year 2000. Potential RNSPS analyzed in this report include the EPA's September 1978 proposed full scrubbing standard and several alternative standards that would permit partial scrubbing. Appendix I, added in June 1979, presents a brief comparison of the final promulgated RNSPS announced on May 25, 1979, and two of the options described in this study.

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ACKNOWLEDGMENTS

Many people contributed to this analysis. We acknowledge first Dr. Lowell Smith of EPA's Office of Energy, Minerals, and Industry for his effective direction in guiding the study in its multiple stages. Teknekron's Software Group under the direction of Marcella Wells provided the capability to program and operate the extensive computer models and data bases required. Dr. Donald Clements significantly added to the development of the pollution control cost and performance models; Virginia Matucha, Harry Nelson, and Rosemary Dunn compiled many of the data bases; and all participated in the model runs. Douglas Pierce carried out many of the sensitivity studies and competitive coal analyses. Dr. Stanley Greenfield offered constructive comments on the numerous issues addressed in this report. The Graphics Group under Charles Chickadel enhanced the presentation of results; particularly helpful in this regard was Carol Johnson, who designed and executed the graphics. Barbara Phillips edited the text, tables, and figures to ensure the production of a clear, cogent, and straightforward document. Finally, word processors Evelyn Kawahara, Sheryl Klemm, Maureen Ash, and Carol See produced the draft report under severe time constraints. The authors gratefully acknowledge these and other members of Teknekron's Energy and Environmental Systems Division for their exemplary efforts. This work was performed under EPA Contract 68-02-3092.

I. INTRODUCTION

Numerous potential revised New Source Performance Standards (RNSPS) have been analyzed.[1-3,8] Because of the many uncertainties surrounding future costs and the responses of individual utilities, the impacts of each standard cannot be predicted with certainty. Hence, emphasis should not be placed on the small marginal differences between similar standards. Accordingly, the Phase 3 projections presented in this report focus on five standards, different in form, that exemplify the differences in likely impacts among feasible full and partial scrubbing options. These standards include the full scrubbing option proposed by EPA as the preliminary revised standard in September 1978 and several partial scrubbing options. City-specific sensitivity analyses for key states were performed for this Phase 3 study to determine the ranges of uncertainty surrounding coal and pollution control choices. Many of the sensitivity studies were carried out with the Coal Assignment Model. The yearly impact projections from 1976 to 2000 were calculated by the Utility Simulation Model. In this Phase 3 analysis the costs and performance of flue gas desulfurization (FGD) technologies were based on wet scrubbing processes, while our analysis of the final promulgated RNSPS given in Appendix I includes both wet and dry FGD technologies.

The Form of the Revised New Source Performance Standard

RNSPS standards are characterized by an emission ceiling, percentages of required SO_2 removal, an emission averaging time (24-hour, 30-day, or annual average), and an emission floor. These terms are explained in the Glossary. As the Phase 3 sensitivity studies and state and regional projections demonstrate, the specific form of the standard will significantly affect the use of low-sulfur and intermediate-sulfur coals and the resulting level of SO_2 emissions.

The sensitivity analyses conducted for this report covered the complete range of SO_2 emission floors and ceilings between 1.2 lb SO_2 per million Btu (10^6 Btu) and 0.2 lb $SO_2/10^6$ Btu, in intervals of 0.1. However, for the national projections, only five distinct standards are presented. These are:

- Current NSPS. This is the current standard of 1.2 lb $SO_2/10^6$ Btu with no mandatory percentage SO_2 removal. Coal sulfur RSD (relative standard deviation) is assumed to be zero for any averaging time. This assumption means that the emission averaging time does not affect compliance with this standard. For purposes of comparison with the alternative RNSPS, this is considered to be an annual average form of the standard. The current NSPS is used as a baseline from which to compare the impacts of alternative RNSPS.

- 0.2 lb floor. This standard requires 85 percent removal of SO_2 over a 24-hour averaging time but permits a drop to 75 percent removal for three days per month. Also, it includes a ceiling of 1.2 lb $SO_2/10^6$ Btu and a floor of 0.2 lb $SO_2/10^6$ Btu. This standard is the preliminary RNSPS promulgated by EPA in September 1978. The ceiling may be exceeded three days per month, while the floor, if controlling, may not be exceeded. Thus, the mean coal sulfur content must be low enough so that the mean plus 2 RSD (24-hour RSD is 0.08 for cleaned coal and 0.15 for uncleaned coal) is less than the 1.2 lb ceiling. Similarly, only those coals for which the mean plus 3 RSD (24-hour) is less than 0.2 lb $SO_2/10^6$ Btu may be scrubbed at less than 85 percent removal efficiency. The only fuels affected by the 0.2 lb floor are those with a sulfur content of less than about 0.5 lb $S/10^6$ Btu. It is assumed that, when the floor controls, partial scrubbing with a fixed bypass will be used. In cases where the ceiling controls, it is assumed that the FGD system will operate at a constant efficiency and that annual average emissions therefore will be less than the ceiling. FGD capital costs are based on a maximum expected coal sulfur content [mean x (1 + 2 or 3 RSD)], while operating costs are based on the mean sulfur content. This standard requires full scrubbing (90 percent or greater annual SO_2 removal) for all coals except those affected by the floor. Greater than 90 percent annual removal would be required only for high-sulfur coals containing more than 3.1 lb $S/10^6$ Btu.

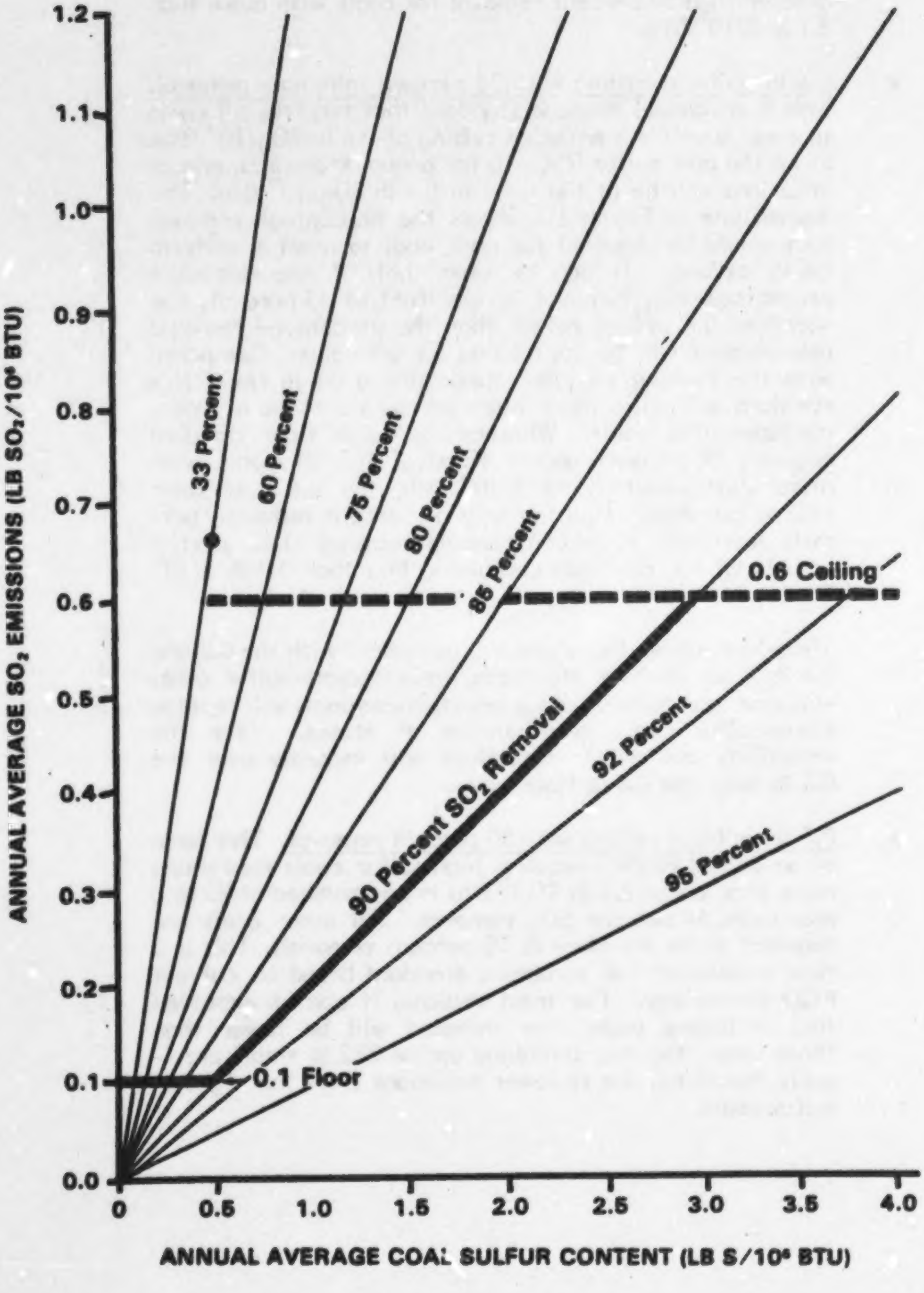
- 0.6 lb floor. This standard is identical to the preceding standard except that the floor is raised. It permits partial scrubbing (less than 85 percent daily SO_2 removal or, equivalently, less than 90 percent annual SO_2 removal) of intermediate-sulfur coals (coals with less than about 1.5 lb S/10^6 Btu). It would require 90 percent annual SO_2 removal for all coals with more than 1.5 lb S/10^6 Btu and greater than 90 percent removal for coals with more than 3.1 lb S/10^6 Btu.

- 0.6 lb uniform ceiling with 33 percent minimum removal. This is an annual average standard that requires all coals to meet a uniform emission ceiling of 0.6 lb SO_2/10^6 Btu. Since the coal sulfur RSD = 0 for annual standards, annual emissions will be at the limit of 0.6 lb SO_2/10^6 Btu. The dashed line in Figure 1-1 shows the percentage removal that would be required for each coal to meet a uniform 0.6 lb ceiling. It can be seen that, if the minimum percentage SO_2 removal is specified as 33 percent, the specified 0.6 ceiling rather than the percentage removal requirement will be controlling for all coals. Compared with the 24-hour standard stipulating a 0.6 lb floor, this standard will allow much more partial scrubbing of intermediate-sulfur coals. Whereas the 0.6 lb floor standard requires 90 percent annual removal for all coals with more than about 1.5 lb S/10^6 Btu, the 0.6 lb uniform ceiling standard, requiring only 33 percent removal, permits less than 90 percent annual removal (i.e., partial scrubbing) for all coals containing less than 3.0 lb S/10^6 Btu.

  Therefore, under this standard, compared with the 0.2 and 0.6 lb floor 24-hour standards, intermediate-sulfur coals will cost less to burn. As a result, these coals will replace lower-sulfur coals in a number of states. (See the sensitivity analyses.) Emissions will increase over the 0.2 lb floor and 0.6 lb floor cases.

- 0.5 lb uniform ceiling with 90 percent removal. This form of an annual RNSPS requires high-sulfur coals containing more than about 2.5 lb S/10^6 Btu to be scrubbed at 90 to a maximum 94 percent SO_2 removal. All other coals are required to be scrubbed at 90 percent removal. This is a "low emissions" full scrubbing standard based on current FGD technology. For most regions, it can be expected that emissions under this standard will be lower than those under the full scrubbing option (0.2 lb floor) previously described, due to lower emissions from the highest-sulfur coals.

Figure 1-1
Comparison of SO_2 Emissions under Annual Average Control Alternatives



The five standards discussed above prescribe either 24-hour or annual periods within which the SO_2 emissions are averaged. A shorter averaging time for a given ceiling implies lower average emissions in order that emission ceilings not be exceeded more than the allowed number of times (i.e., sulfur variability as measured by the RSD becomes greater for shorter averaging periods). The minimum specified percentage SO_2 removal also depends on averaging time. Ninety percent annual SO_2 removal is assumed to be achieved if a minimum 85 percent daily SO_2 removal is maintained.

Table I-1 illustrates the effects of averaging time for a number of potential RNSPS. For comparative purposes, each of the RNSPS presented in the table are compared at the same annual emission level.

Impacts of the Alternative Revised New Source Performance Standards

In Section 2, Summary of Principal Results, the projected impacts of alternative RNSPS are grouped into three categories: environmental impacts; economic impacts; and resource utilization. The absolute impact levels, the comparative levels relative to the baseline, and the results of the sensitivity analyses are presented for each category. In addition, Section 2 contains a subsection devoted specifically to general conclusions from the sensitivity analyses, as well as a subsection comparing the full and partial scrubbing options. The impact and sensitivity discussions in Section 2 proceed as follows:

- Environmental Impacts
  - Regional SO_2 emissions*
  - SO_2 emissions from RNSPS-controlled plants

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* Emissions of numerous other pollutants — NO_x, particulates, trace metals, and so forth — were also calculated but are not discussed in this report.

Table I-1

Averaging Time and SO_2 Standards with Equivalent Annual Emissions

Revised NSPS SO_2 Standard[a]				Equivalent Standard (Same Annual Emissions)								
				1-Day Average[b]			30-Day Average[c]			365-Day Average[d]		
Ceiling (lb/10^6 Btu)	Floor (lb/10^6 Btu)	Minimum Removal (%)	Averaging Time (Days)	Effective Ceiling	Floor	Minimum Removal	Effective Ceiling	Floor	Minimum Removal	Effective Ceiling	Floor	Minimum Removal
1.2	0	0	365	1.56 - 2.34[e]	0	0	1.45 - 1.74[f]	0	0	1.2	0	0
0.6	0	33	365	0.79 - 1.17[g]	0	31	0.72 - 0.87[h]	0	32	0.6	0	33
0.5	0	90	365	0.98	0	85	0.72	0	88	0.5	0	90
1.2	0.2	85	1	1.2	0.2	85	0.89	0.13	88	0.615	0.092	90
1.2	0.6	85	1	1.2	0.6	85	0.89	0.40	88	0.615	0.276	90
0.8	0	55	30	0.9 - 1.08[i]	0	53	0.8	0	55	0.55 - 0.64[j]	0	56
1.2[k]	0.6	90	30	2.1	1.2	87	1.2	0.6	90	1.0	0.5	92
0.6[k]	0	70	30	1.2	0	68	0.6	0	70	0.5	0	72

[a] A key element of this table is the variability of coal sulfur content. For uncleaned coals, the assumed coal sulfur RSD (relative standard deviation) = 0.15 for a 24-hour averaging time, 0.069 for a 30-day averaging time, and 0.0 for an annual averaging period. For cleaned coals, the RSD = 0.075 for a 24-hour averaging time, 0.03 for a 30-day averaging time, and 0.0 for an annual averaging period. In practice, lot size as well as averaging time and coal properties can change the RSD.

[b] Ceiling exemption allowed three days per month; no floor exemptions allowed.

[c] No exemptions. Thirty-day average may not exceed ceiling or floor.

[d] No exemptions. Annual average may not exceed limit.

[e] The effective ceiling is a function of coal sulfur content (Coal S) in pounds per million Btu. One-day ceiling = 1.47 + 0.144 Coal S when Coal S is less than 6, and 2.34 when Coal S is equal to or greater than 6. The effective ceiling yields the same annual emissions for coals with different sulfur contents.

[f] The effective ceiling is a function of coal sulfur content (Coal S) in pounds per million Btu. Thirty-day ceiling = 1.42 + 0.054 Coal S when Coal S is less than 6, and 1.74 when Coal S is equal to or greater than 6.

[g] The effective ceiling is a function of coal sulfur content (Coal S) in pounds per million Btu. One-day ceiling = 0.737 + 0.144 Coal S when Coal S is less than 3, and 1.17 when Coal S is equal to or greater than 3. For Coal S less than 0.38, minimum removal controls.

[h] The effective ceiling is a function of coal sulfur content (Coal S) in pounds per million Btu. Thirty-day ceiling = 0.708 + 0.054 Coal S when Coal S is less than 3, and 0.87 when Coal S is equal to or greater than 3. For Coal S less than 0.45, minimum removal controls.

[i] The effective ceiling is a function of coal sulfur content (Coal S) in pounds per million Btu. The effective ceiling = 0.832 + 0.089 Coal S when Coal S is equal to or less than 2.76, and 1.08 when Coal S is greater than 2.76. For Coal S less than 0.74 and ceiling less than 0.9, minimum removal controls.

[j] The effective ceiling is a function of coal sulfur content (Coal S) in pounds per million Btu. The effective ceiling = 0.678 - 0.045 Coal S when Coal S is equal to or less than 2.76 and 0.55 when Coal S is greater than 2.76. For Coal S less than 0.74 and ceiling greater than 0.64, minimum removal controls.

[k] The last two RNSPS shown represent the final promulgated RNSPS. Coals with sulfur content below about 0.9 lb S per million Btu can be scrubbed at a minimum of 70 percent SO_2 removal efficiency, as indicated by the last line. Other coals will be controlled by higher percentage removals as indicated by the previous line.

  - FGD capacity
  - FGD sludge and coal ash production
- Economic Impacts
  - Cumulative pollution control investment
  - National average monthly residential electricity bill
  - Present value of total utility expenditures
  - SO_2 emission and percentage cost changes
  - Incremental costs of SO_2 reduction
- Resource Utilization
  - Utility fossil fuel consumption
  - Utility water consumption
  - Coal production for electric utilities
  - Western coal shipped east of the Mississippi River
- Sensitivity Analyses
  - Ranges of cost uncertainties
  - Distinguishing differences among the impacts of various partial scrubbing options
  - Implications and reliability of cost-effectiveness measures
  - Implications of lower versus higher future FGD costs
  - The form of the revised standard
- Comparison of one full and one partial scrubbing option
  - SO_2 emissions
  - Economic costs
  - Resource utilization
  - Other factors

Many measures of impacts can be used, and these impacts can be aggregated from the county level to the national level with the Utility Simulation Model. In Section 3, Key Questions and Answers, impact measures and aggregations are more extensively treated through a question and answer format. The questions answered in Section 3 are as follows:

I. WHAT ARE THE LIKELY IMPACTS OF A REVISED NSPS?

  a. How will the national costs and SO_2 emission reductions based on higher (PEDCo) FGD costs be distributed regionally in 1995 for the full scrubbing option (0.2 lb floor) and the partial scrubbing options (0.6 lb floor and 0.6 lb uniform ceiling)?

  b. The regional emission projections include emissions from both old and new generating units. The revised NSPS will affect only those units in operation after 1982, and these plants and their successors should be operating for over 35 years after 1983. What are the differences in emissions from these RNSPS plants compared with the older units subject to more lenient standards?

  c. What are the emission projections for coal-fired plants when TVA's lower FGD cost estimates are used?

  d. What are the principal utility capital investments for various standards using lower as compared with higher estimates of future scrubber costs?

  e. How do the alternative RNSPS differ in their impacts on primary resource consumption and solid waste generation?

  f. How are utility coal production and consumption influenced by the SO_2 standard and by different estimates of FGD costs?

II. WHAT ARE THE DIFFERENCES BETWEEN THE PROJECTED IMPACTS OF THE FULL AND PARTIAL SCRUBBING ALTERNATIVES?

  a. What are the cost and emission differences between the various full and partial scrubbing options?

  b. How does the form of the revised standard influence the costs of pollution controls?

III. HOW WILL UTILITY COAL CHOICES IN KEY STATES BE AFFECTED BY DIFFERENT SO_2 EMISSION STANDARDS AND UNCERTAINTIES IN KEY FACTORS?

a. What estimates can be made regarding the typical utility costs of buying, transporting, and burning different coals, and of required pollution controls, as a function of the SO_2 standard?

b. What is the sensitivity of fuel-cycle costs to coal mine prices?

c. What is the sensitivity of fuel-cycle costs to coal transportation costs?

d. What is the sensitivity of fuel-cycle costs to western coal characteristics?

e. What is the sensitivity of coal and pollution control choices to different engineering estimates of FGD costs?

IV. HOW ACCURATE AND RELIABLE ARE MEASURES OF THE COST EFFECTIVENESS OF VARIOUS STANDARDS?

2. SUMMARY OF PRINCIPAL RESULTS

This section presents some of the major conclusions of the Phase 3 sensitivity studies and impact projections for alternative revised New Source Performance Standards (RNSPS).

Environmental Impacts

Included below are the key results on regional SO_2 emissions and percentage cost changes, RNSPS-plant SO_2 emissions, FGD capacity, and FGD sludge and coal ash production.

SO_2 Emissions

- National power-plant SO_2 emissions from 1985 to 2000 are shown in Figure 2-1. SO_2 emissions increase under the current NSPS because of the rapid increase in coal-fired power generation after 1985. SO_2 emissions begin to decrease under the revised NSPS after 1995, both because of the tighter standards and because of retirements of older plants (plants regulated by more lenient State Implementation Plan standards). However, under the current NSPS, SO_2 emissions increase through the year 2000 even though old plants are being retired.

- National SO_2 emissions in 1995 decrease by 19.7 percent under the full scrubbing option (0.2 lb floor), by 17.5 percent under the 0.6 lb floor, and by 12.7 percent under the 0.6 lb uniform ceiling.

- Regional SO_2 emissions in 1995 change under alternative RNSPS as shown in Figure 2-2. Compared with projections for the baseline case (the current NSPS), the greatest emission reductions occur in the West South Central region. There emissions decrease by 44 percent under the full scrubbing option (0.2 lb floor) and by 28 percent under the 0.6 lb uniform ceiling. In the Pacific region, SO_2 emissions decrease by 57 percent under the full scrubbing option and by 29 percent under the 0.6 lb uniform ceiling

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Figure 2-1
National Power-Plant SO_2 Emissions
Higher FGD Costs

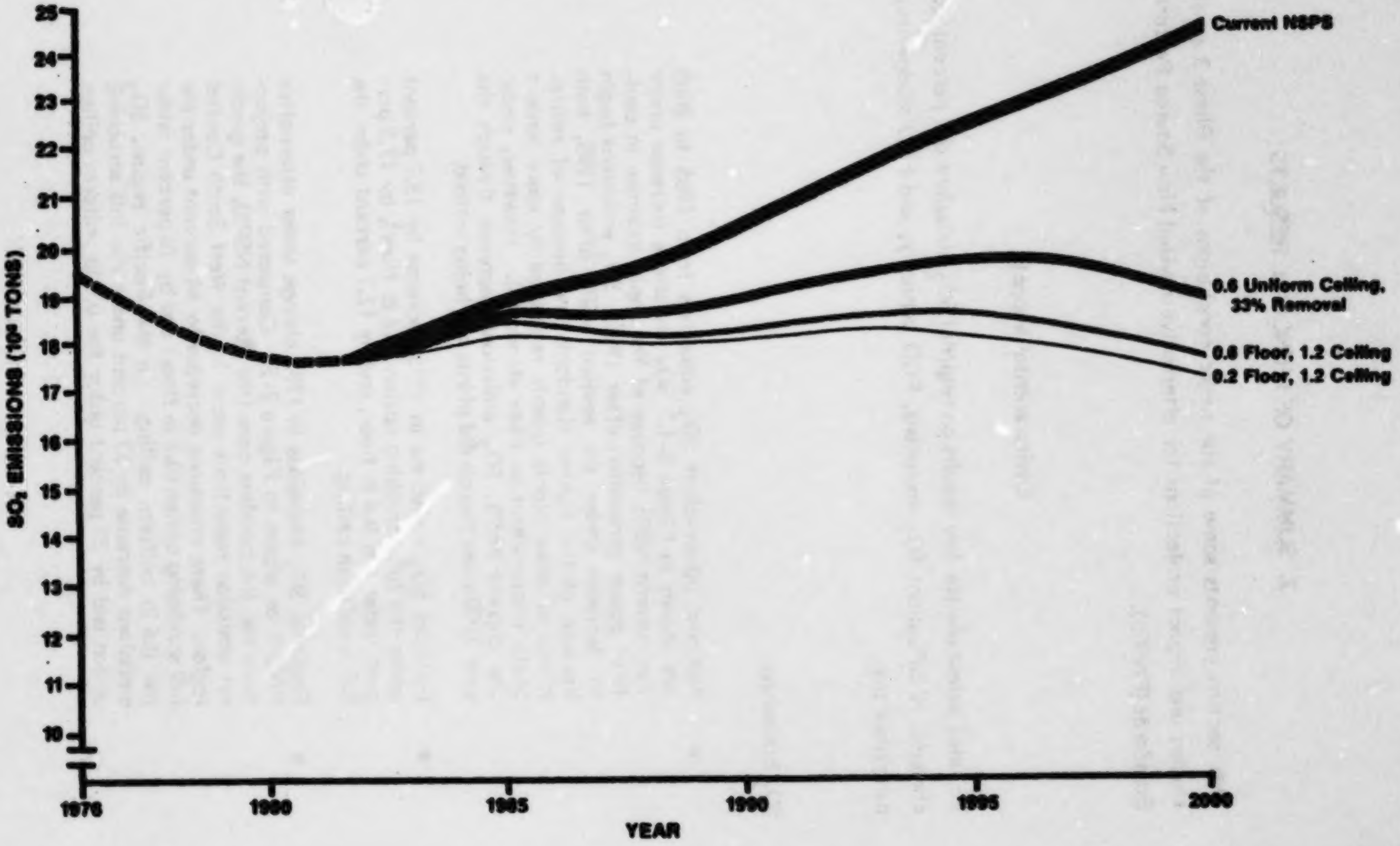
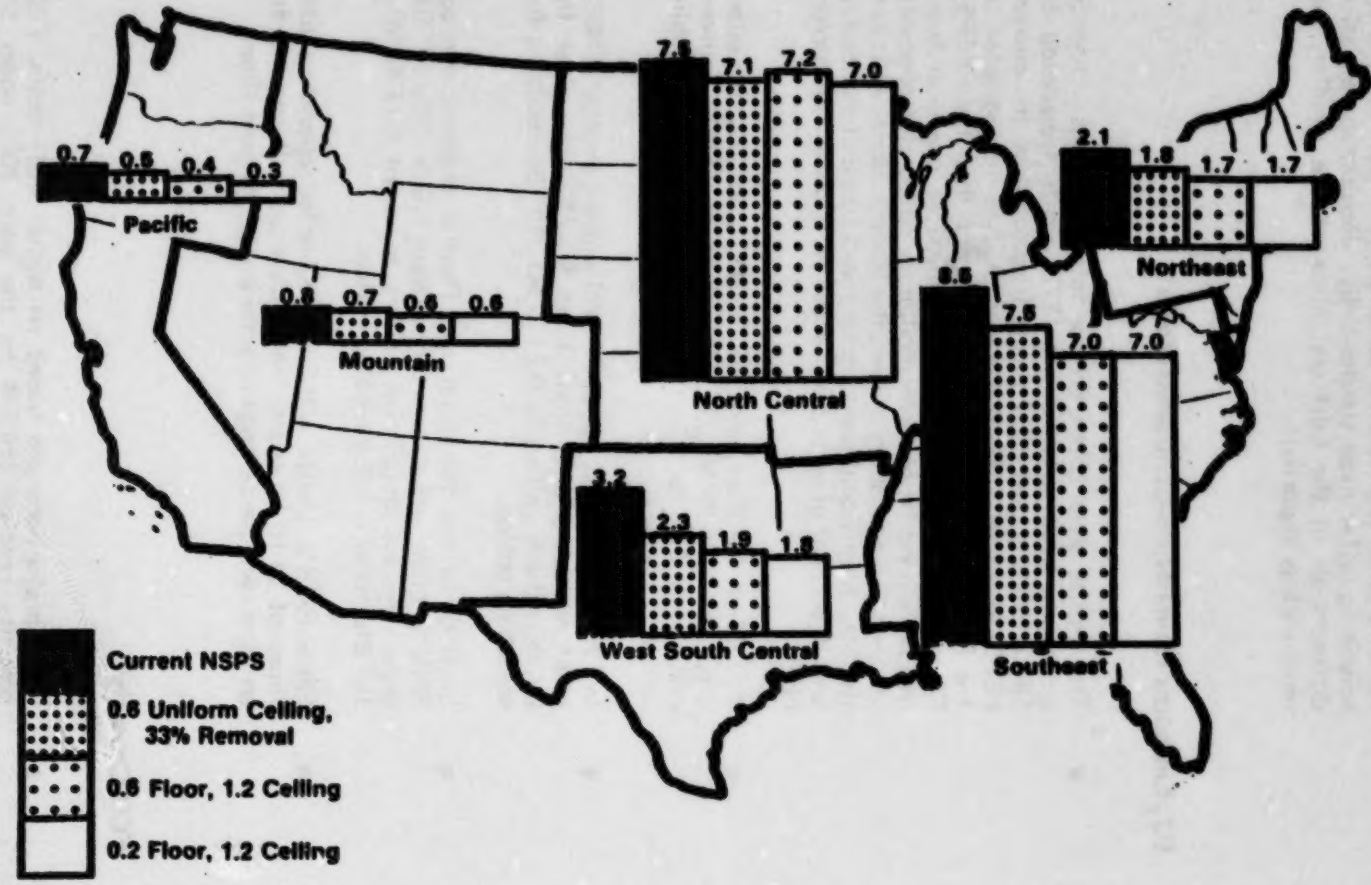


Figure 2-2
Regional SO_2 Emissions (10^6 Tons), 1995
Higher FGD Costs


0.7
0.5
0.4
0.3
Pacific
0.8
0.7
0.6
0.6
Mountain
7.5
7.1
7.2
7.0
North Central
3.2
2.3
1.9
1.8
West South Central
8.5
7.5
7.0
7.0
Southeast
2.1
1.8
1.7
1.7
Northeast
Current NSPS
0.6 Uniform Ceiling, 33% Removal
0.6 Floor, 1.2 Ceiling
0.2 Floor, 1.2 Ceiling

(a partial scrubbing option). It is in the Pacific and West South Central regions that the impacts of full and partial scrubbing differ most substantially. Percentage emission differentials in the East and Midwest are smaller, but nevertheless important.

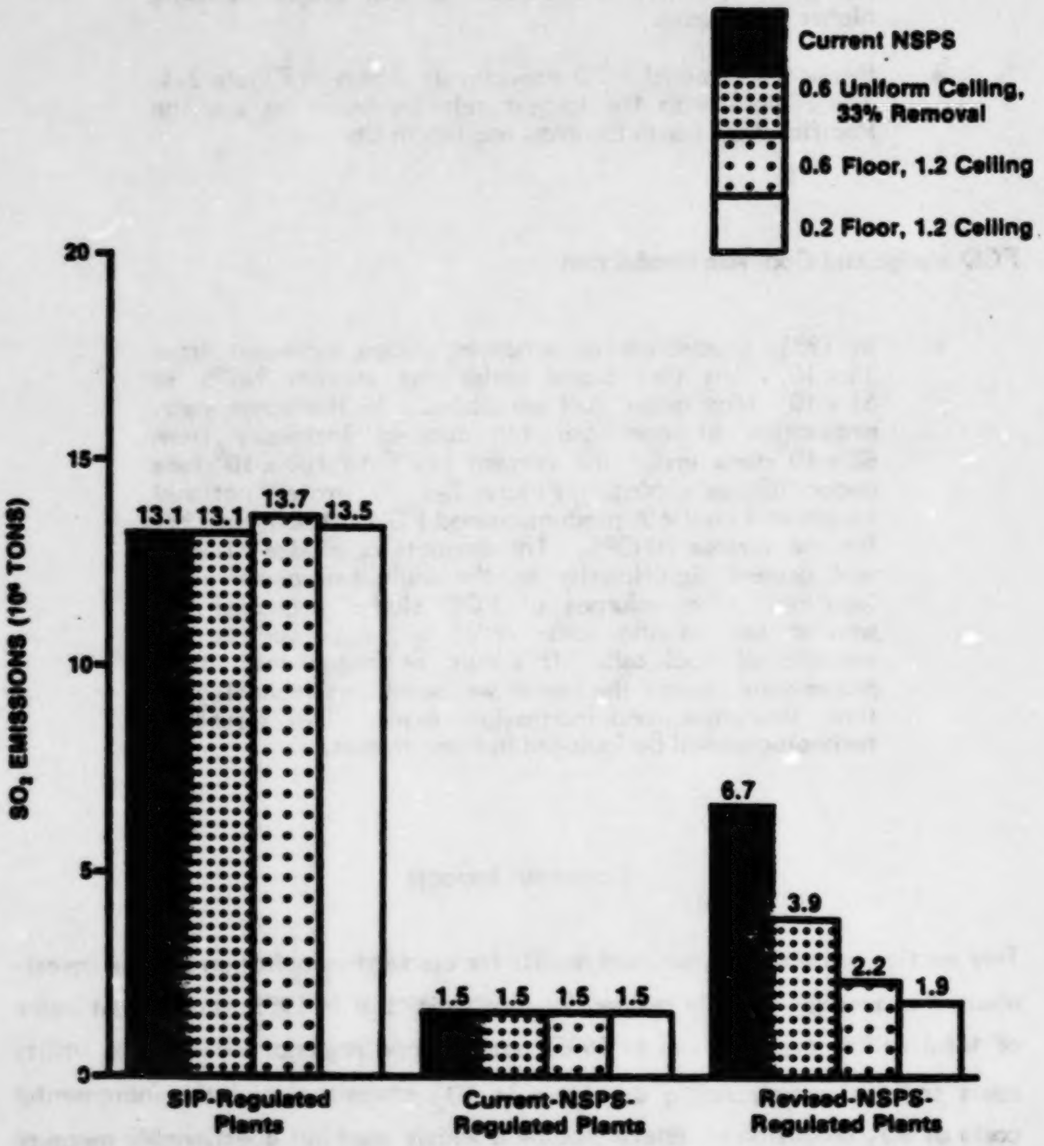
SO_2 Emissions from RNSPS-Controlled Plants

- The results given above are for total emissions — that is, emissions from existing pre-1977 plants (regulated by SIPs), existing post-1977 plants (regulated by the current NSPS), and post-1982 plants (assumed to be regulated by the RNSPS or by SIPs more stringent than the RNSPS). Figure 2-3 illustrates how SO_2 emissions are distributed in 1995 among these three regulatory categories of plants. Under a full scrubbing option, the RNSPS plants emit half the SO_2 they would emit under the 0.6 lb uniform ceiling and 28 percent of what they would emit under the current NSPS.
- In 1995 in the East, average RNSPS plant SO_2 emissions drop from 0.6 lb $SO_2/10^6$ Btu under the 0.6 lb uniform ceiling to 0.36 lb $SO_2/10^6$ Btu under a full scrubbing option.
- In 1995 in the West South Central region, average RNSPS plant emissions drop from 0.6 lb $SO_2/10^6$ Btu under the 0.6 lb uniform ceiling to 0.29 lb $SO_2/10^6$ Btu under a full scrubbing option.
- In 1995 in the Mountain and Pacific regions, average RNSPS plant emissions drop from 0.6 lb $SO_2/10^6$ Btu under the 0.6 lb uniform ceiling to about 0.16 lb $SO_2/10^6$ Btu under a full scrubbing option.
- Since RNSPS plants will have expected operating lifetimes of 35 to 40 years, their emissions will account for an increasing percentage of total emissions over time.

FGD Capacity

- When projections are based on higher FGD costs, FGD capacity reaches 194 GW by the year 2000 under the

Figure 2-3
National SO_2 Emissions from Coal-Fired Power Plants, 1995
Higher FGD Costs



current NSPS, 423 GW under the 0.6 lb uniform ceiling, and 510 GW under a full scrubbing option. The net coal capability in 2000 is projected to be about 630 GW.

- When projections are based on lower FGD costs, FGD capacity reaches 295 GW by 2000 under the current NSPS (a substantial increase over the higher FGD cost projection), 452 GW under the 0.6 lb uniform ceiling, and 505 GW under the 0.2 lb floor, full scrubbing option. The net coal capability is the same as that projected using higher FGD costs.
- Projected regional FGD capacity is shown in Figure 2-4. The regions with the largest relative increases are the Pacific, West South Central, and North Central.

FGD Sludge and Coal Ash Production

- In 1995, production of scrubber sludge increases from 15×10^6 tons (dry basis) under the current NSPS to 51×10^6 tons under full scrubbing. In the same year, production of coal ash for disposal increases from 88×10^6 tons under the current NSPS to 100×10^6 tons under full scrubbing. Figure 2-5 illustrates national sludge and coal ash production and FGD capacity in 1995 for the various RNSPS. The impacts of sludge disposal will depend significantly on the individual power-plant location. The volumes of FGD sludge produced are smaller but of the same order of magnitude as the volumes of coal ash. It should be noted that these projections assume the use of wet scrubbing technologies: lime, limestone, and magnesium oxide. Dry scrubbing technologies will be included in later studies.

Economic Impacts

This section presents key national results for cumulative pollution control investment, the average monthly residential electricity bill in 1995, the present value of total utility expenditures to 1995, national and regional increases in utility costs and the corresponding decreases in SO_2 emissions, and the incremental costs of SO_2 reduction as determined by a widely used but questionable measure of cost effectiveness, expressed as dollars per ton of SO_2 removed.

Figure 2-4
Regional FGD Capacity (GW), 1995
Higher FGD Costs

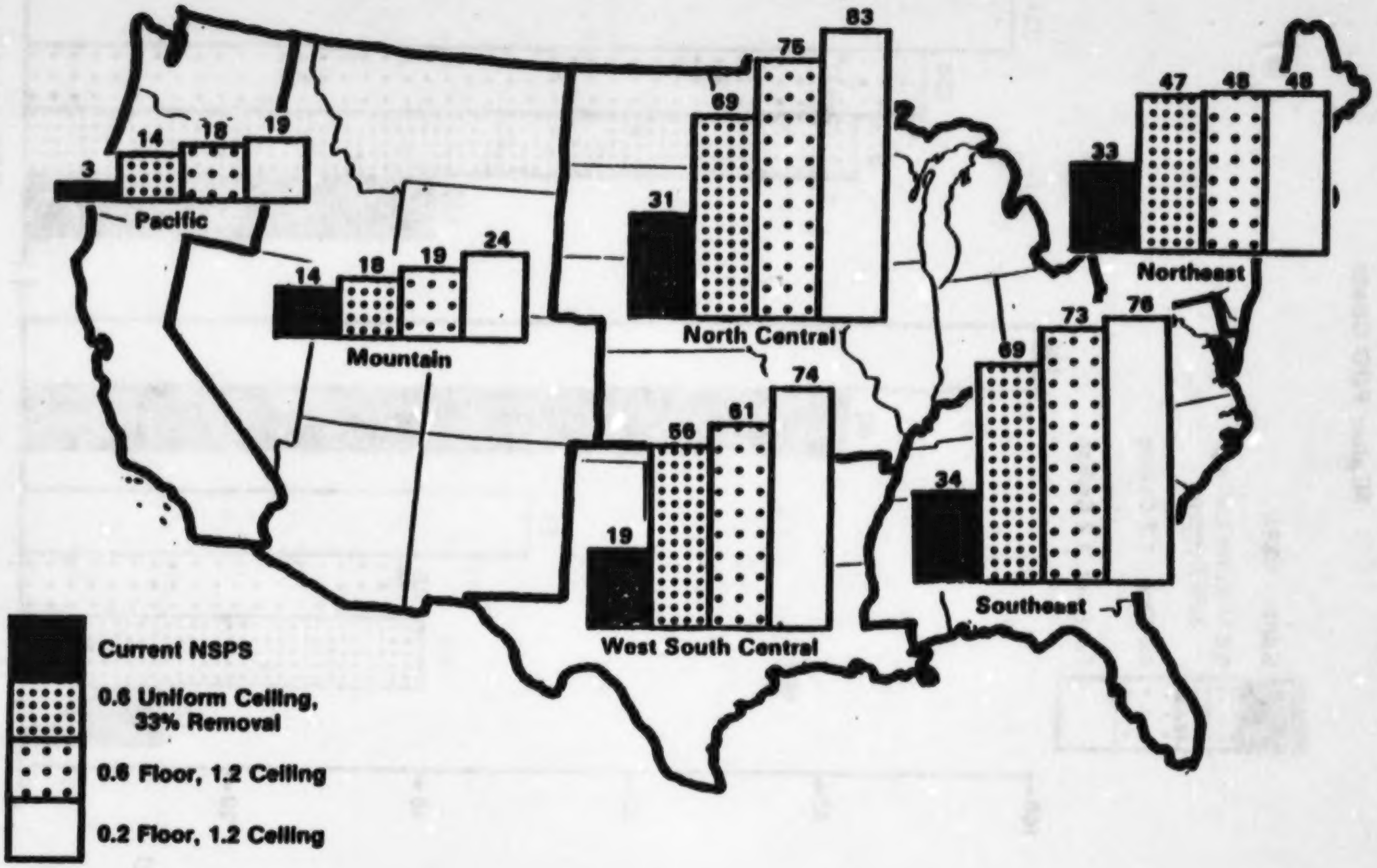
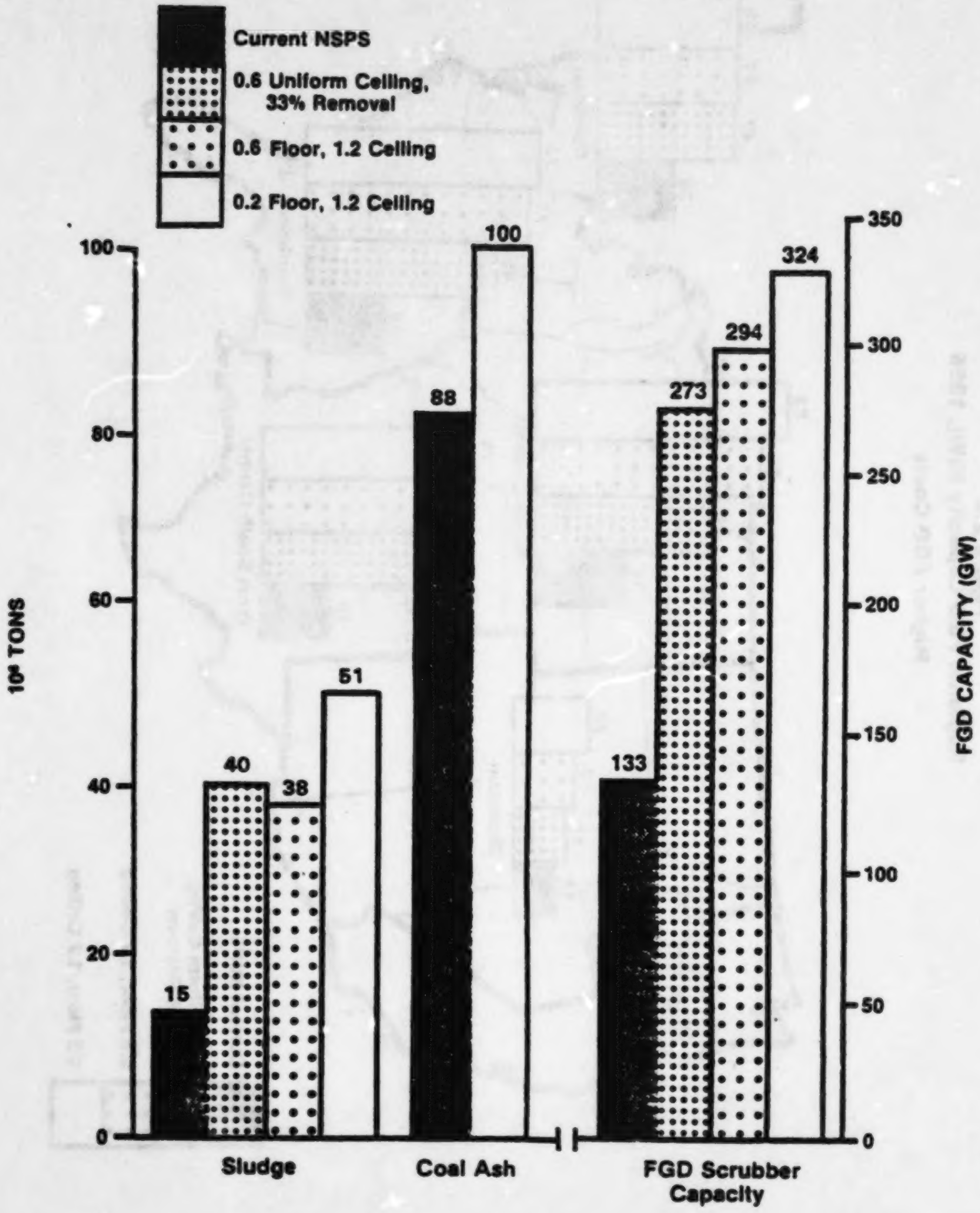

3
14
18
19
Pacific
14
18
19
24
Mountain
31
69
76
83
North Central
19
56
61
74
West South Central
33
47
48
48
Northeast
34
69
73
76
Southeast
■ Current NSPS
▦ 0.6 Uniform Ceiling, 33% Removal
⁘ 0.6 Floor, 1.2 Ceiling
□ 0.2 Floor, 1.2 Ceiling

Figure 2-5
National Sludge and Coal Ash Production and FGD Capacity, 1995
Higher FGD Costs



Cumulative Pollution Control Investment

- Between 1983 and 2000, under the current NSPS, cumulative investment for pollution controls (including water and air pollution controls for electric utilities) is projected to be $40 billion (1975 $). Under the 0.6 lb uniform ceiling, pollution control investment increases by $28 billion (70 percent); and under the full scrubbing option it increases by $42 billion (105 percent). These results are based on the higher (PEDCo) FGD cost estimates, which reflect conservatism regarding FGD design.

- As indicated earlier, under the lower (TVA) FGD cost estimates (which are about 40 percent lower than PEDCo's and reflect a less conservative approach), FGD capacity under the current NSPS significantly increases. This is because lower FGD costs would make scrubbing more economically attractive. Pollution control investments from 1983 to 2000 under the current NSPS are $34 billion (1975 $). Under the 0.6 lb uniform ceiling they increase by $14 billion (41 percent); and under the full scrubbing option they increase by $18 billion (53 percent). The higher and lower FGD cost projections are compared in Figure 2-6.

National Average Monthly Residential Electricity Bill

- The national average monthly residential electricity bill in 1995 increases from $54.68 under the current NSPS to $56.21 under the 0.6 lb uniform ceiling (a 2.8 percent increase). Under the full scrubbing option it rises to $57.37 (a 4.9 percent increase). These projections assume the higher FGD cost estimates. Using the lower estimates reduces the expected monthly cost of electricity in 1995: the cost is $52.67 under the current NSPS, $53.75 (a 2.1 percent increase) under the 0.6 lb uniform ceiling, and $53.99 (a 2.5 percent increase) under the 0.2 lb floor, full scrubbing option. A more stringent full scrubbing option, the 0.5 lb ceiling with 90 percent removal, would lead to slightly greater cost increase (to $54.61 a month, or a 3.6 percent increase). Using the lower instead of the higher FGD cost estimates reduces the projected average residential electricity bill under the 0.2 lb floor, full scrubbing option by over $3 per month in 1995. Figure 2-7 compares the 1995 monthly residential bills.

Figure 2-6
Comparison of Cumulative Pollution Control Investment, 1983-2000,
Reflecting Higher and Lower FGD Costs
(Billions 1975$)

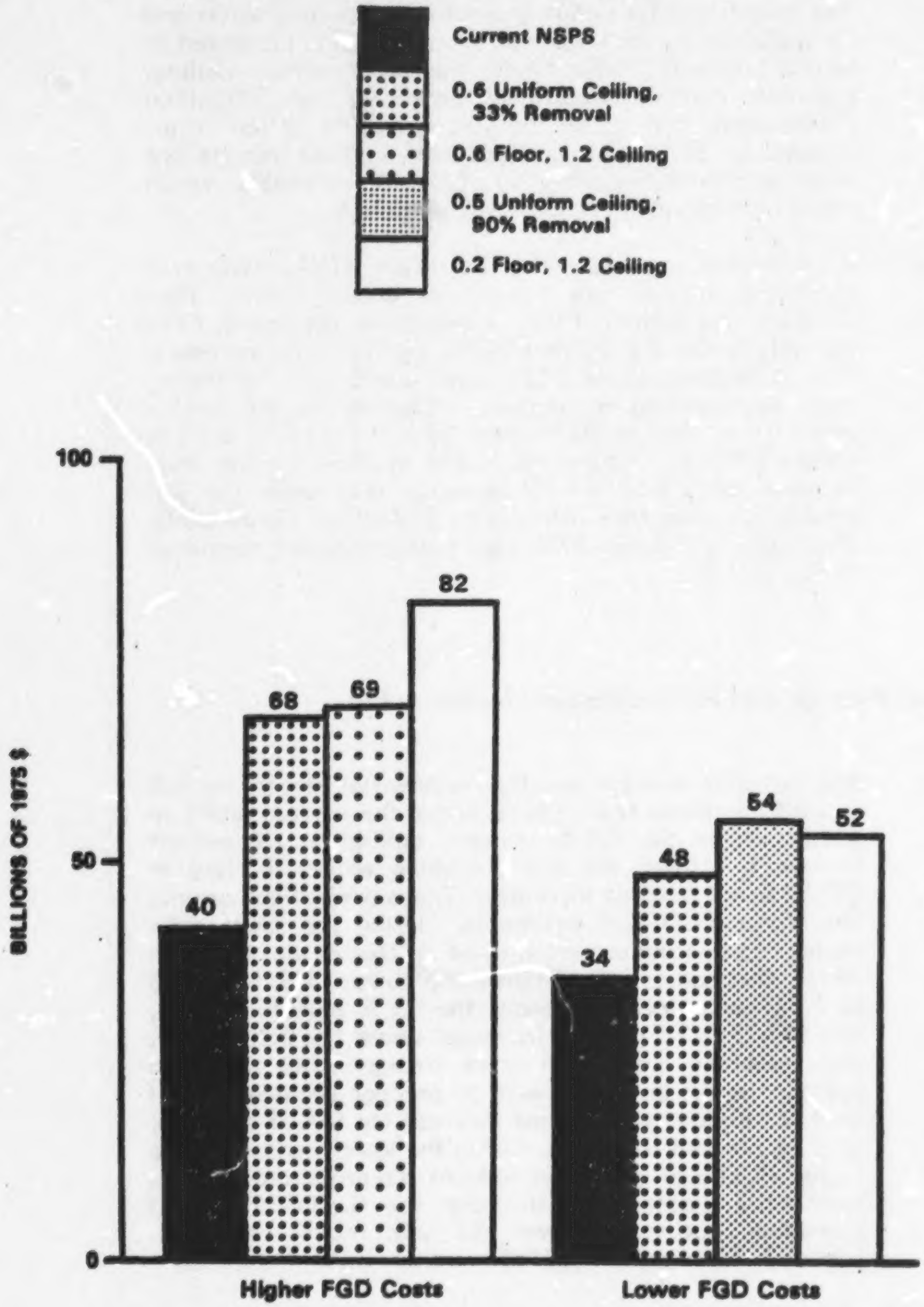
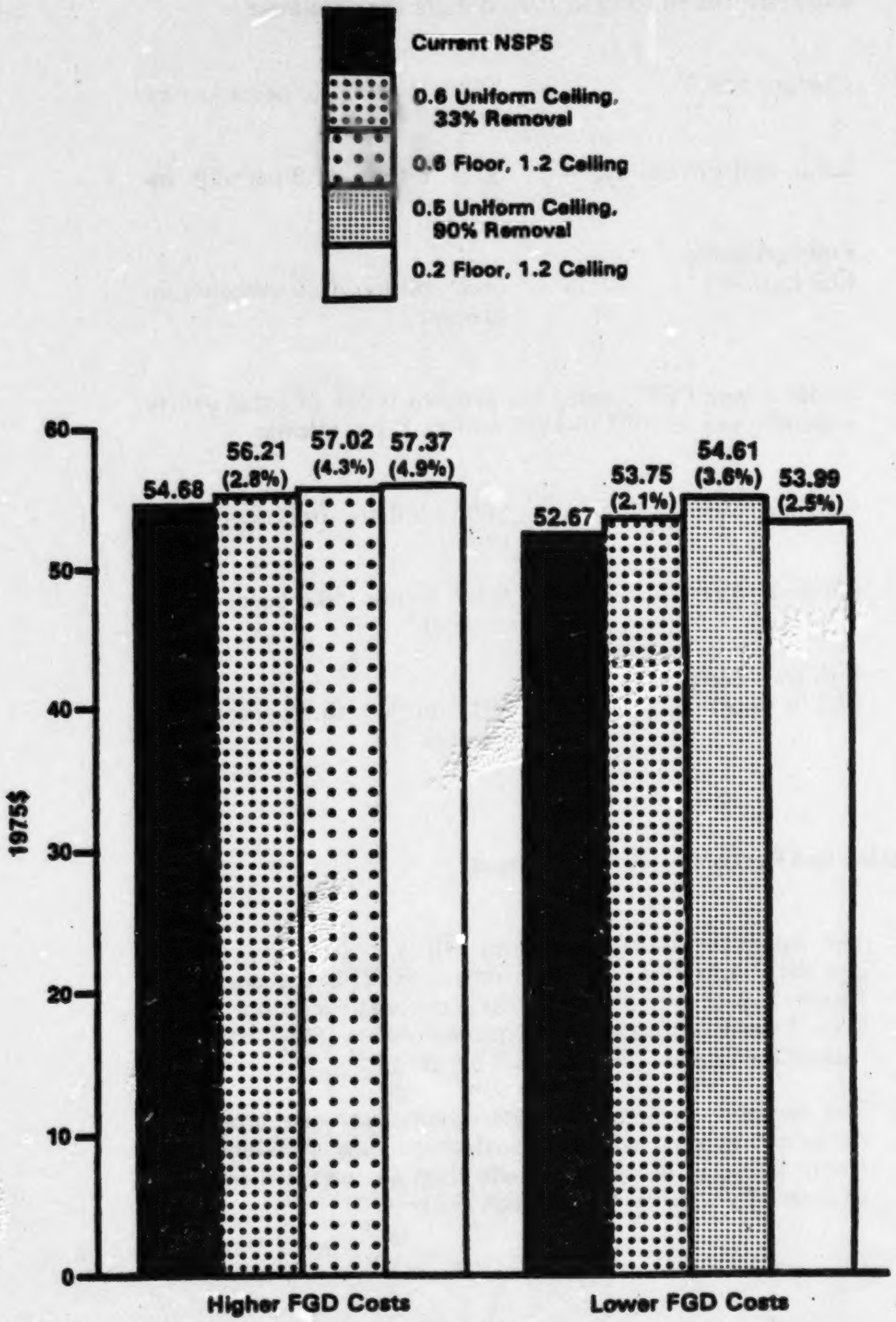


Figure 2-7
National Average Residential Monthly Electric Bill in 1995 and Percentage Increase from Current NSPS
(1975$)



Present Value of Total Utility Expenditures to 1995

- Under higher FGD costs, the present value of total utility expenditures to 1995 in 1975 dollars is as follows:

  Current NSPS - $819 billion (0 percent increase)

  0.6 lb uniform ceiling - $826 billion (0.8 percent increase)

  Full scrubbing (0.2 lb floor) - $832 billion (1.6 percent increase)

- Under lower FGD costs, the present value of total utility expenditures to 1995 in 1975 dollars is as follows:

  Current NSPS - $805 billion (0 percent increase)

  0.6 lb uniform ceiling - $809 billion (0.6 percent increase)

  Full scrubbing (0.2 lb floor) - $811 billion (0.7 percent increase)

SO_2 Emission and Percentage Cost Changes

- The increases in national total utility costs and percentage SO_2 reductions for alternative RNSPS are shown in Figure 2-8. Note that the cost increases range only from 3 to 5 percent, while the corresponding SO_2 emission reductions range from 13 to 20 percent.
- The regional projections generally reflect the projected national impacts, with the eastern regions showing relatively less change in magnitude than the western regions, as shown in Figures 2-9 through 2-11.

Figure 2-8

National Percentage Increase in Total Utility Cost and Percentage Decrease in SO_2 Emissions for Revised NSPS, 1995

Higher FGD Costs

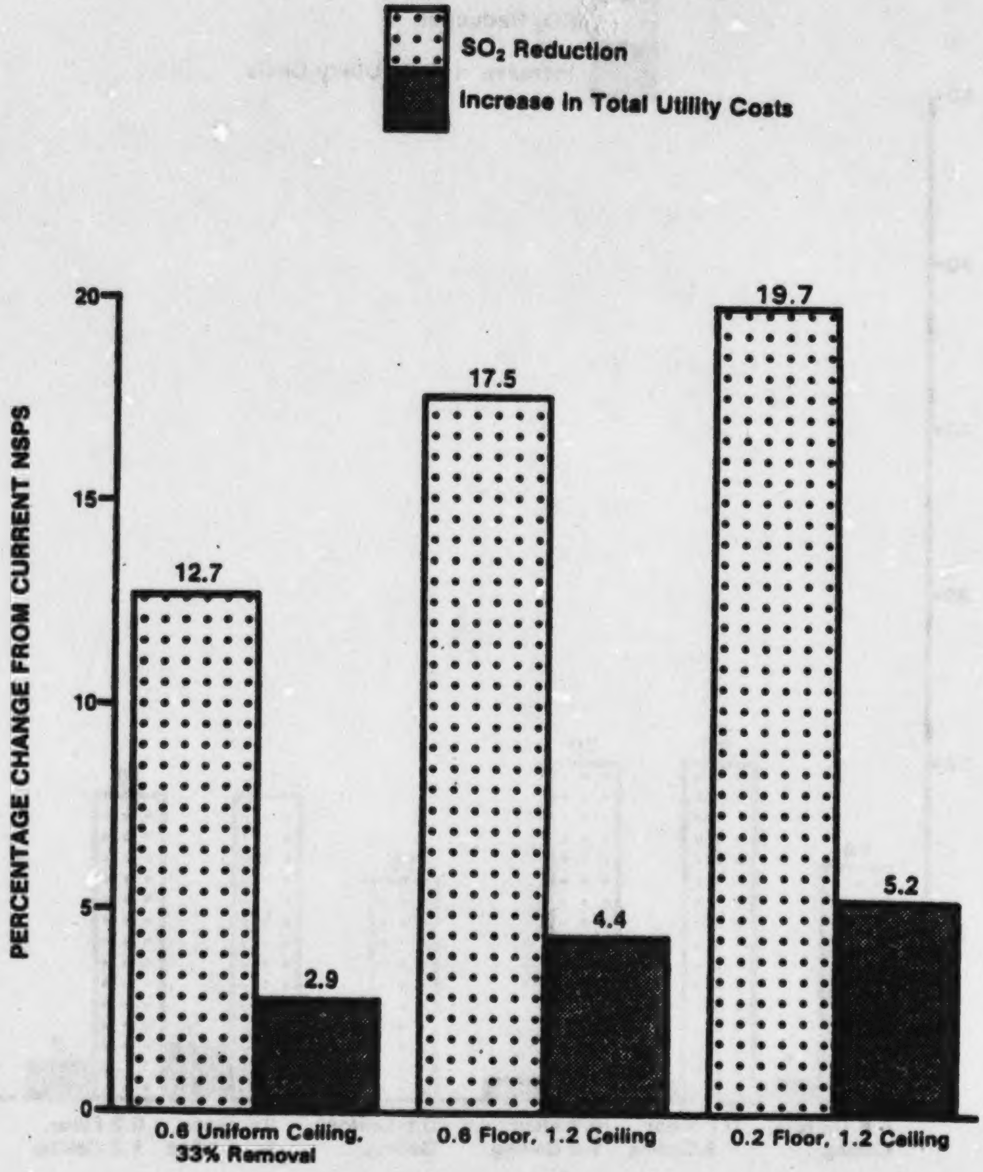


Figure 2-9
Comparison of SO_2 Emission Reductions and Increases in Total Utility Costs for Revised NSPS Relative to Current NSPS, 1995
Higher FGD Costs

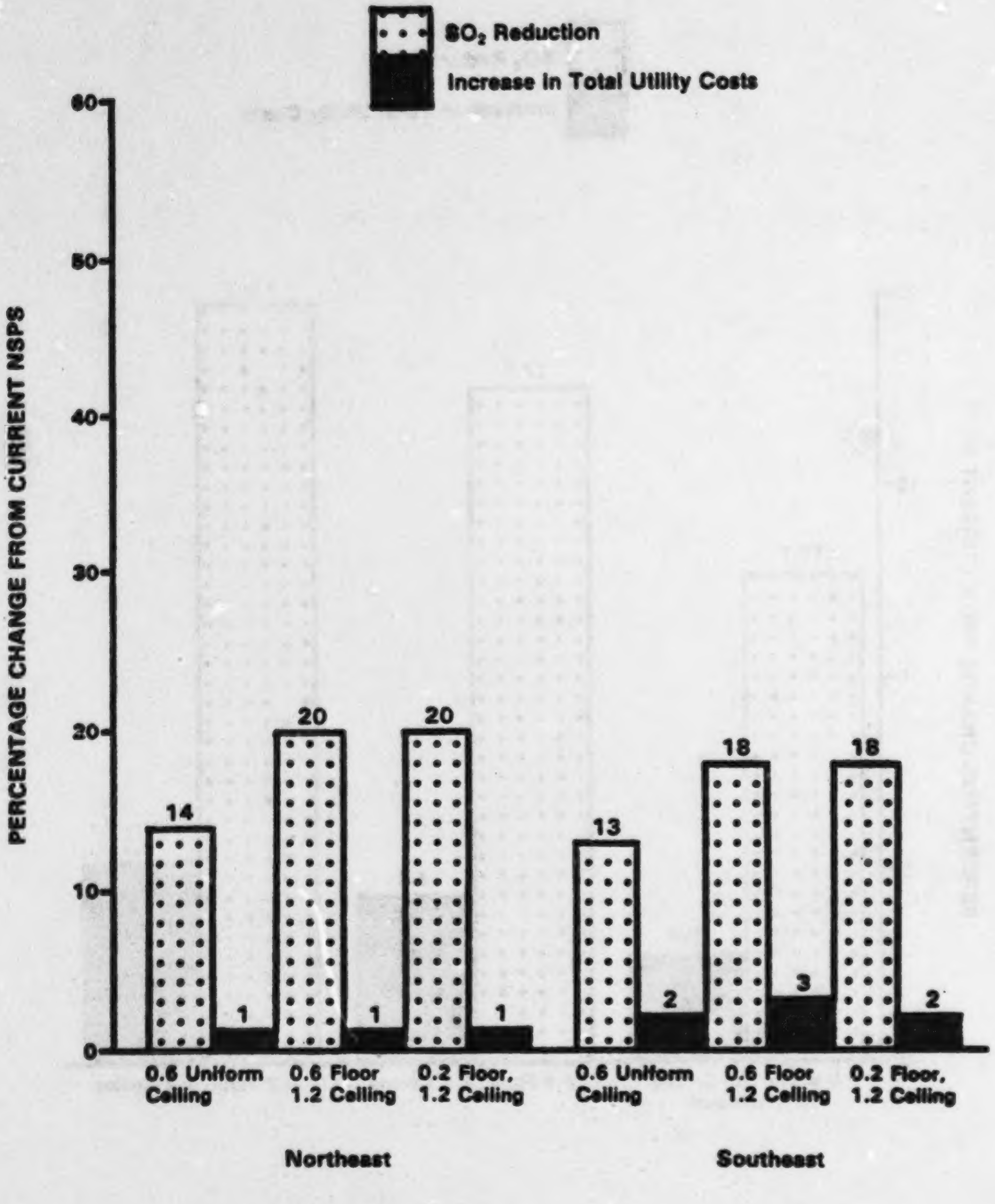


Figure 2-10
Comparison of SO_2 Emission Reductions and Increases in Total Utility Costs for Revised NSPS Relative to Current NSPS, 1995
Higher FGD Costs

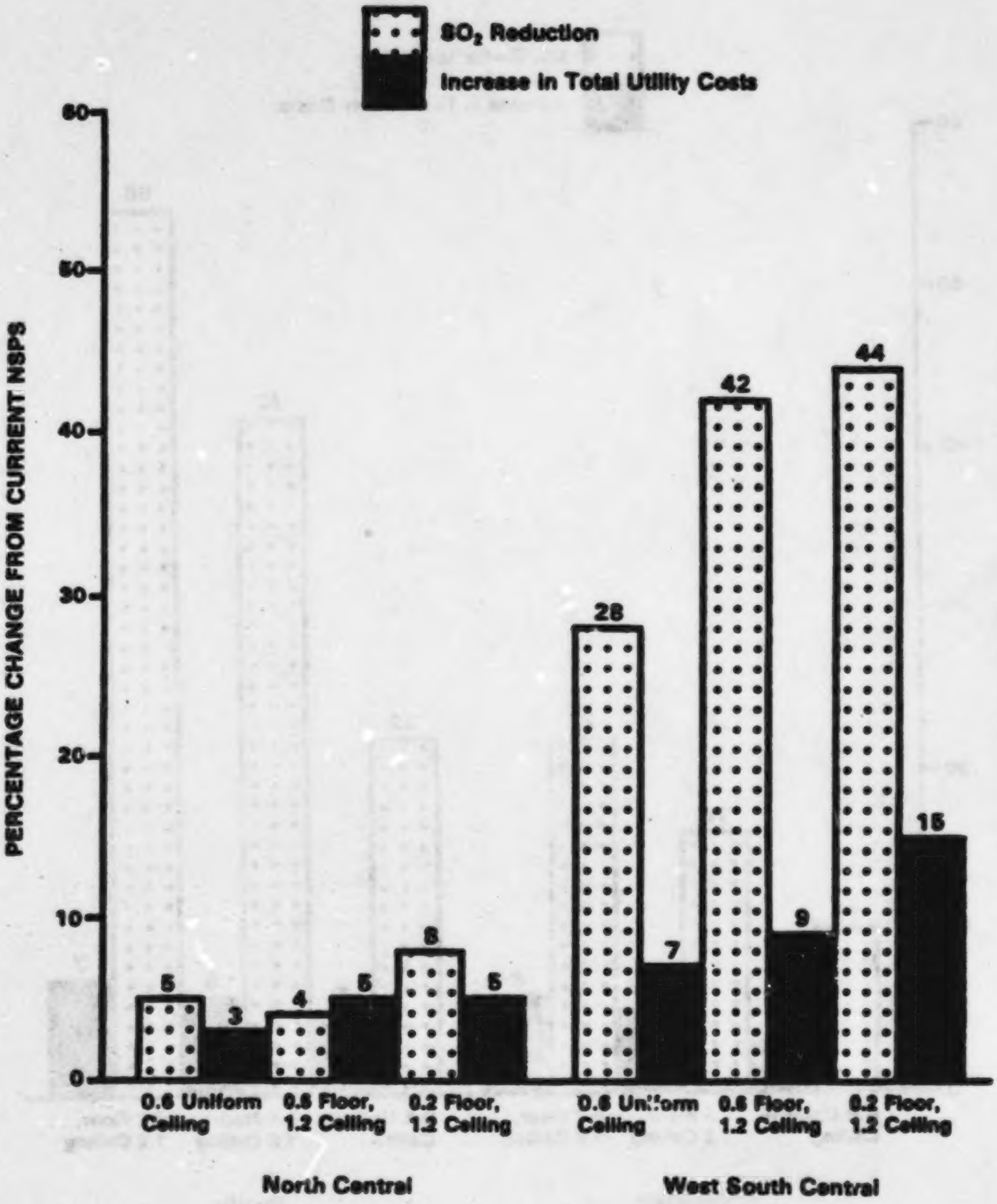
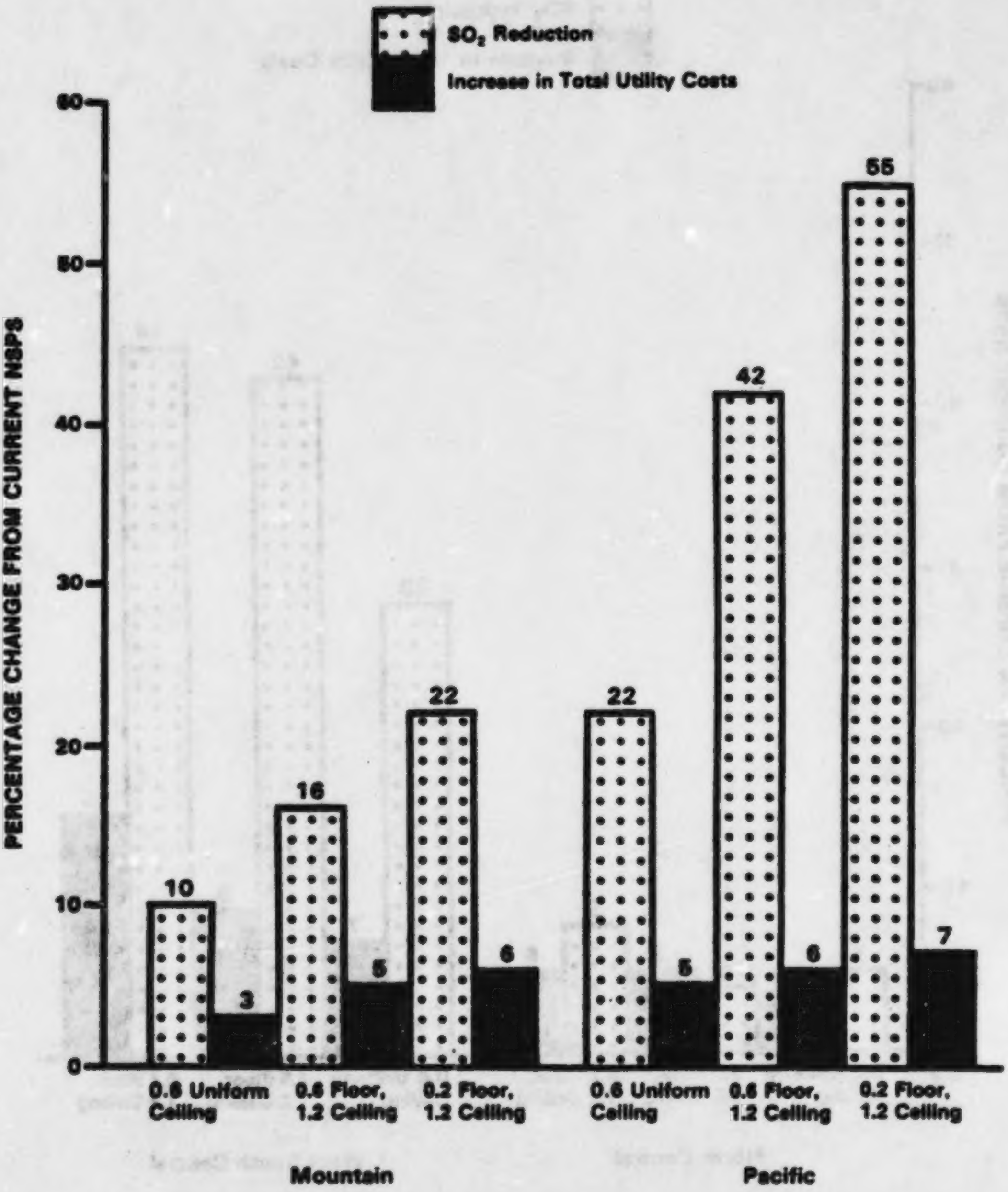


Figure 2-11
Comparison of SO_2 Emission Reductions and Increases in Total Utility Costs for Revised NSPS Relative to Current NSPS, 1995

Higher FGD Costs



- Total utility costs under the higher FGD cost assumptions are slightly greater for the 0.6 lb floor than for the 0.2 lb floor in the Southeast, yet the same is not true for the other regions. This phenomenon is caused by two factors — the delivered price of coal and the scrubbing requirement. Under the 0.6 lb floor, southeastern utilities consume more low-sulfur coal and scrub less than under the 0.2 lb floor. Under the 0.2 lb floor, utilities will use locally available higher-sulfur coals with a lower delivered price, which offsets the slightly increased cost of scrubbers. The close similarity between these two RNSPS options (0.2 lb and 0.6 lb floor) is discussed in Section 3.

Incremental Costs of SO_2 Reduction: Dollars per Ton of SO_2 Removed

Dollars per ton of SO_2 removed has been used in other studies as a measure of the cost effectiveness of alternative RNSPS. Section 3 discusses the shortcomings of this measure due to the uncertainties which affect its calculation. As shown in Section 3, great care must be exercised when considering this measure. The absolute uncertainty and the relative uncertainties of this measure when compared for alternative RNSPS make comparisons with other model results difficult. This measure also varies significantly by region.

- Remembering the above caveats and using higher FGD costs, the 1995 incremental costs per ton of SO_2 removed in 1975 dollars are as follows:

0.6 lb uniform ceiling	$1,375
0.6 lb floor	$1,531
0.2 lb floor	$1,591

- Remembering the above caveats and using lower FGD costs, the 1995 incremental costs per ton of SO_2 removed in 1975 dollars are as follows:

0.6 lb uniform ceiling	$900
0.2 lb floor	$900
0.5 lb ceiling, 90 percent removal	$831

Resource Utilization

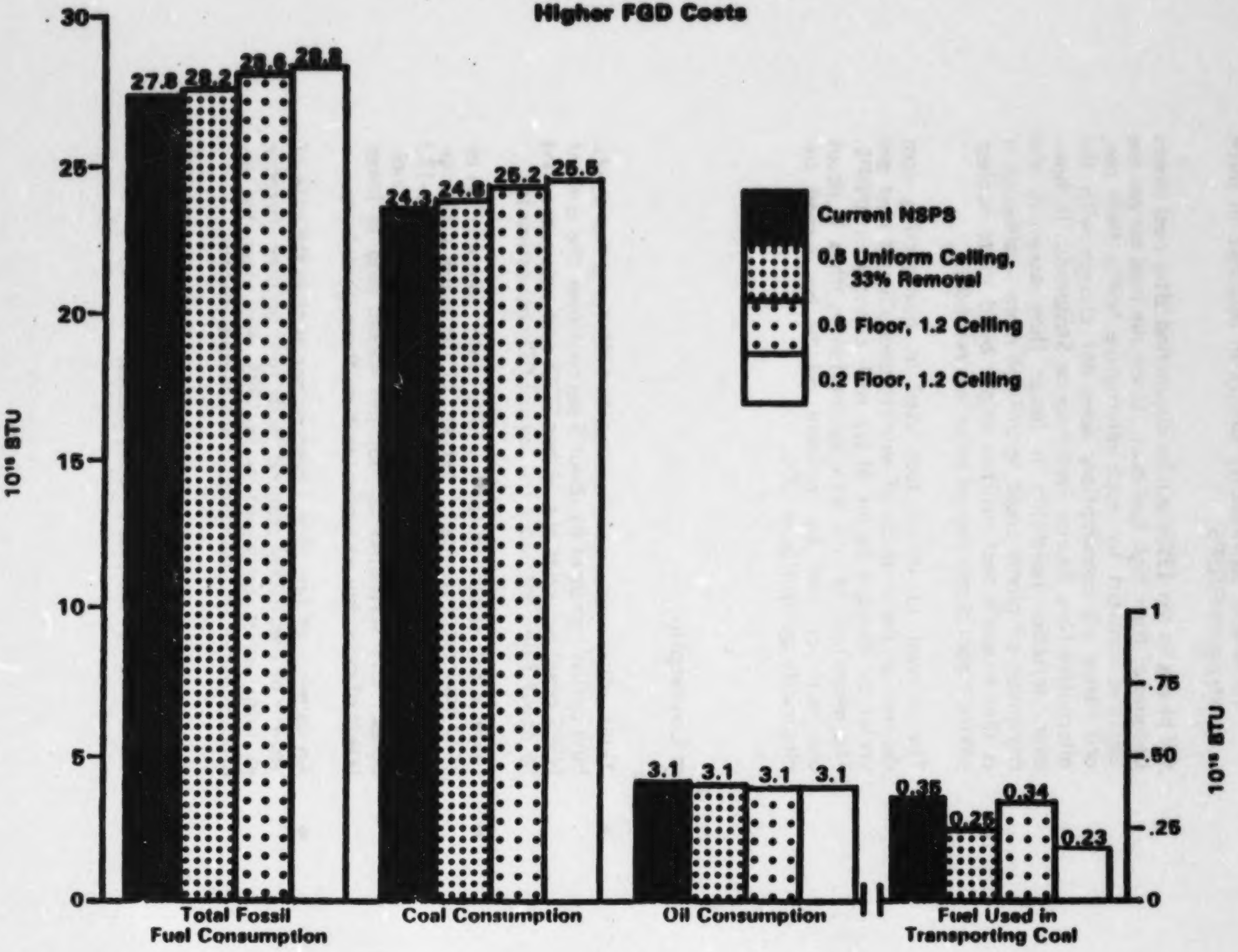
This section compares the impacts of alternative RNSPS on utility fossil fuel consumption, on water consumption for cooling and FGD, on regional utility coal production, and on movements of western coal to the East.

Utility Fossil Fuel Consumption

Figure 2-12 shows projected utility consumption of fossil fuels in 1995.

- Total coal consumption rises slightly as the SO_2 emission standard becomes more stringent. This is due primarily to FGD energy requirements.
- Projected oil consumption is largely independent of the revised NSPS but does depend significantly on oil plant retirement schedules. Considerable oil plant retirements are projected to occur in the decade between 1985 and 1995, and these will reduce utility oil consumption over time. (See Appendixes F and H.) In the USM, oil plants are retired on the basis of age, announced utility plans, and government coal conversion programs, and not strictly on the basis of oil price. This is appropriate for a number of reasons:
    - High fuel oil costs are usually passed through to the customer
    - Oil plants are often located in urban areas where coal storage space is not available
    - It is much easier for a utility to operate an existing oil plant than to site, build, and operate a new coal plant
    - Oil plants are often located in strategic locations in the distribution grid and in 1995 will be used in a cycling mode
    - Residual oil for electric utilities should be available as long as petroleum is refined for gasoline for use in motor vehicles, etc. The availability of oil will depend more on future government oil policy than on oil prices, which are already high compared to coal.

Figure 2-12
Utility Fossil Fuel Consumption, 1996
Higher FGD Costs



- Lower utility reserve margins in 1995, about 20 percent, will discourage differential retirements of the remaining oil capacity simply in response to more stringent RNSPS

Oil plants in the 1990s will be dispatched after coal plants because of their high fuel cost. Since the load curves are assumed constant for each alternative NSPS, their use, and hence oil consumption, does not change with the alternative New Source Performance Standards. If, however, scrubber reliability is lower than assumed, the remaining oil plants could be utilized more — although it is also possible that utilities might build more nuclear plants if coal plants proved to be less reliable.

- The amount of diesel fuel used in transporting coal depends on the amounts of western coal shipped east and varies by about a factor of 1.5 with changes in RNSPS. The magnitude of this oil consumption in Btu's is about one-tenth of that for residual oil to be burned for electricity generation in 1995.

Utility Water Consumption

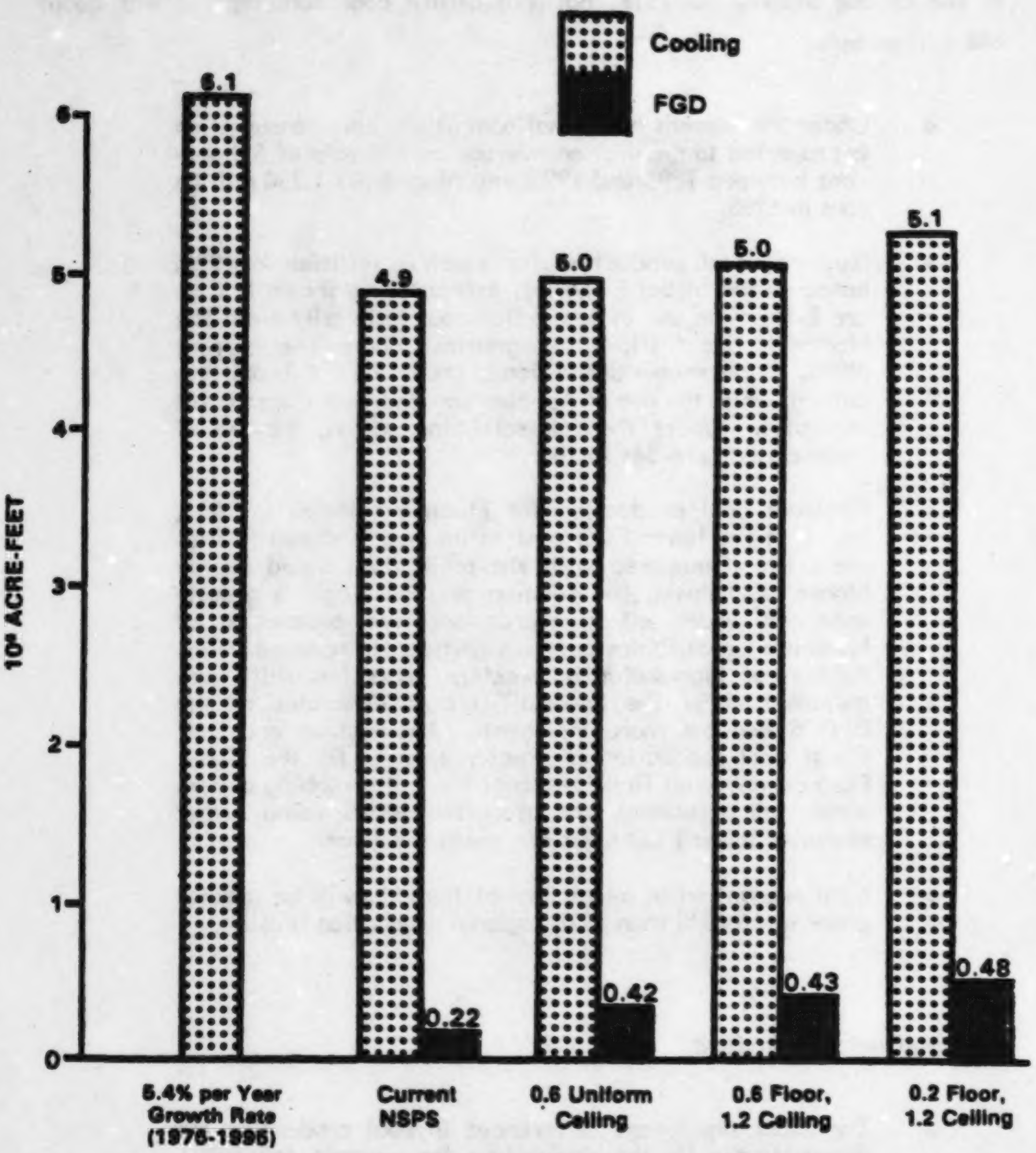
- Total utility water consumption in 1995 for a full scrubbing option increases by about 5 percent over the current NSPS baseline under the higher FGD cost estimates, and by about 3 percent under the lower FGD cost estimates.

- Under a full scrubbing option, total water consumption by FGD equipment is about 9 percent of the water consumption for generation cooling purposes. (See Figure 2-13.) These calculations assume only wet scrubbing technologies. Dry scrubbing technologies should lead to lower levels of consumptive water use than those given here.

- An increase of less than 1 percent per year in the rate of growth of electricity demand leads to a greater increase in total water consumption in 1995 than does the increased use of scrubbing under alternative RNSPS.

- As with SO_2 emissions and scrubber sludge disposal, the impacts of increased water consumption will depend on the location of individual power plants.

Figure 2-13
Utility Water Consumption, 1995
Higher FGD Costs



Coal Production for Electric Utilities

The electric utility sector consumes approximately two-thirds of the coal mined in the United States. In 1976, national utility coal consumption was about 446 million tons.

- Under the current NSPS, national utility coal consumption is projected to grow at an average annual rate of 5.3 percent between 1985 and 1995, reaching about 1,250 million tons in 1995.

- Regional coal production for electric utilities in 1995, based on the higher FGD cost estimates, is shown in Figure 2-14. The use of low-sulfur coal (primarily from the Northern Great Plains) is greatest under the current NSPS. It decreases dramatically under the 0.6 lb uniform ceiling, while the use of Appalachian and Gulf Coast coals increases. Under the full scrubbing option, the use of these coals increases further.

- Regional coal production for electric utilities in 1995, based on the lower FGD cost estimates, is shown in Figure 2-15. Compared with the projections based on the higher FGD costs, the position of local coals is greatly enhanced under all standards and the production of Northern Great Plains coal is significantly reduced. Production of high-sulfur midwestern coals for utility use increases under the lower FGD cost estimates as the RNSPS become more stringent. Appalachian and Gulf Coast coal production is greater than under the higher FGD costs for all RNSPS except the full scrubbing option: under full scrubbing, the projected levels using either higher or lower FGD costs are about the same.

- Coal production in all regions of the U.S. will be greater under all RNSPS than 1978 regional production levels.

Western Coal Shipped East

- The most significant differences in coal production are demonstrated by the projections for western low-sulfur coals shipped east of the Mississippi River. Figure 2-16 shows the tonnages of western coal shipped east (primarily to Midwestern states) under the higher FGD costs; Figure 2-17 shows the tonnages under the lower FGD costs. Under the current NSPS, eastward shipments of western coal in 1995 are 240 x 10^6 tons under the higher costs but only 72 million tons under the lower costs. Under the 0.6 lb uniform ceiling, these shipments are reduced to 136 and 66 million tons, respectively. Using lower future FGD costs substantially increases the projected use of local coals.

- As illustrated in Figures 2-16 and 2-17, shipments of western coal to the East also change significantly with the RNSPS. The current NSPS and the 0.6 lb floor standard show the greatest use of western coal east of the Mississippi. The 0.6 lb uniform ceiling decreases the use of western coal. Full scrubbing options render local coal use more attractive and minimize the use of western coal in the East.
- Under either the higher or lower FGD cost assumptions, the 0.6 lb uniform ceiling enhances the position of intermediate-sulfur coals, while the full scrubbing option leads to the greatest use of cheaper, local coals (over all sulfur contents).

Sensitivity Analyses

All the results discussed above can be considered as results of sensitivity analyses of the national and regional effects of alternative assumptions and alternative RNSPS. As an integral part of the Phase 3 RNSPS study, city-specific sensitivity analyses were performed to determine ranges over which the impacts of alternative standards will be influenced by factors over which EPA has no control. These sensitivity analyses are discussed in greater detail in Section 3 and Appendix C.

Ranges of Cost Uncertainties for Key Cities

In the key cities (see Appendix C for examples), the range of cost uncertainties and utility responses due to parameters over which EPA has no control can be

Figure 2-14
Utility Coal Production (10^6 Tons), 1995
Higher FGD Costs

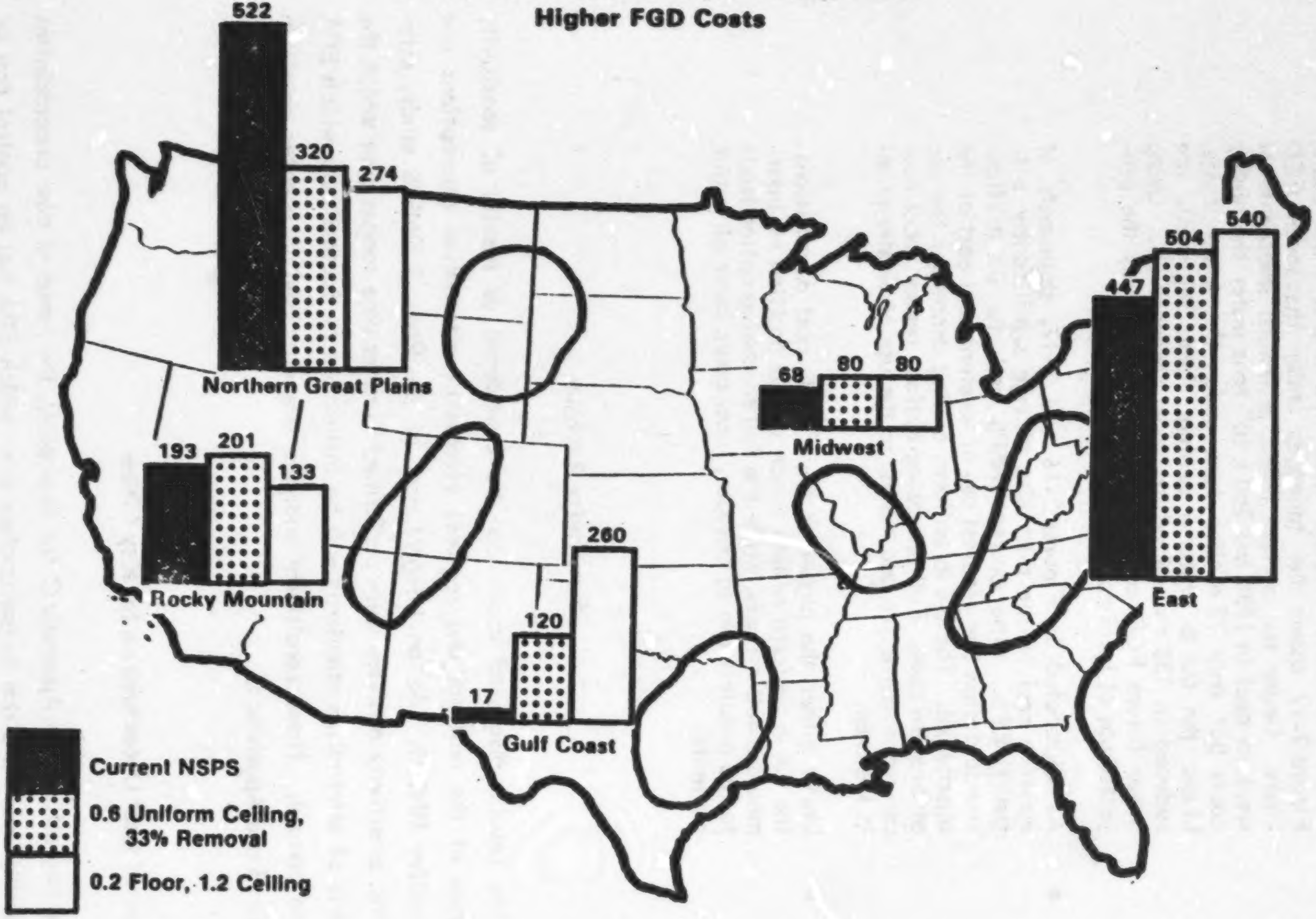

522
320
274
Northern Great Plains
193
201
133
Rocky Mountain
17
120
260
Gulf Coast
68
80
80
Midwest
447
504
540
East
Current NSPS
0.6 Uniform Ceiling, 33% Removal
0.2 Floor, 1.2 Ceiling

Figure 2-15
Utility Coal Production (10^6 Tons), 1995
Lower FGD Costs

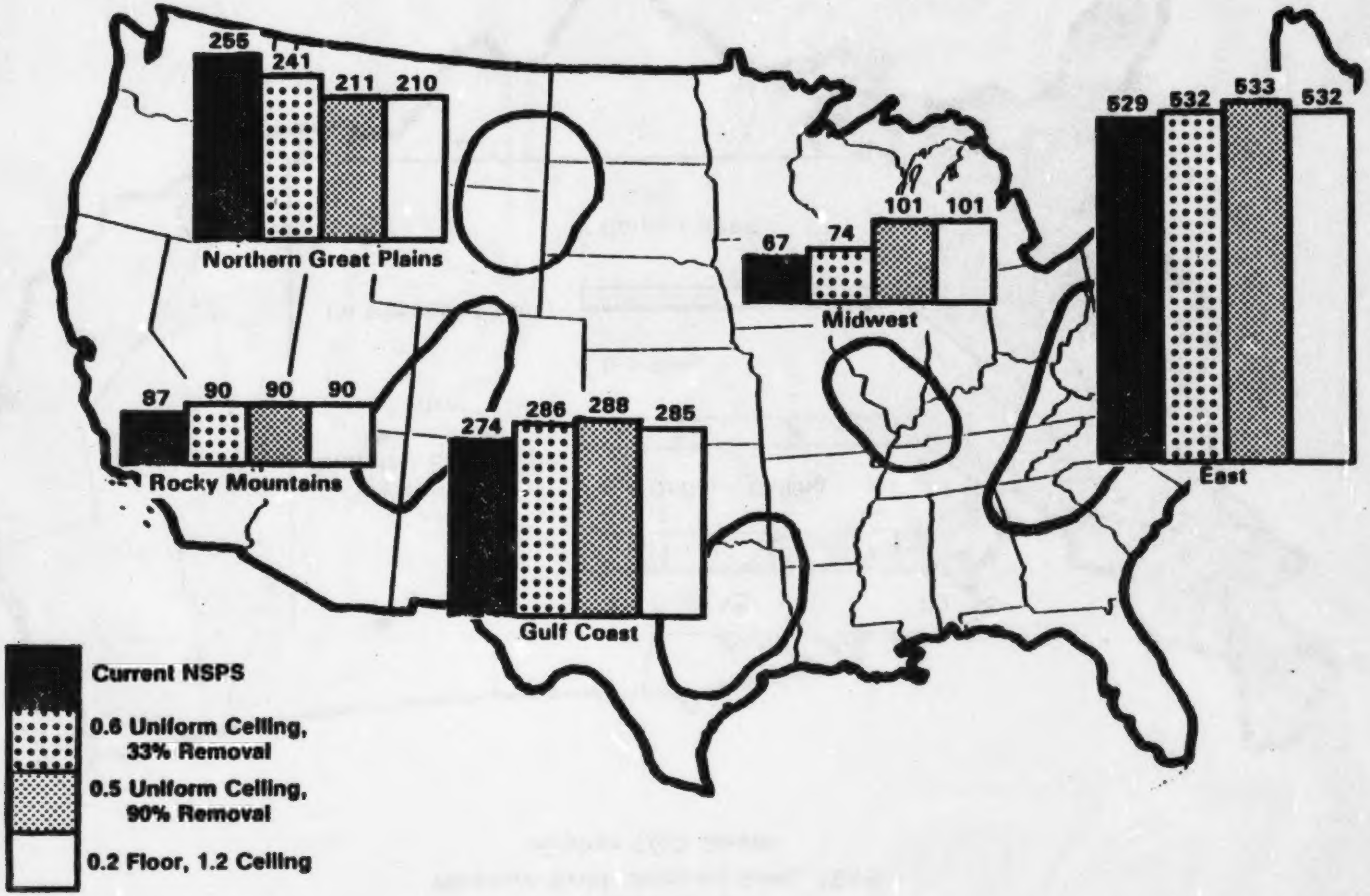

255
241
211
210
Northern Great Plains
87
90
90
90
Rocky Mountains
274
286
288
285
Gulf Coast
67
74
101
101
Midwest
529
532
533
532
East
Current NSPS
0.6 Uniform Ceiling, 33% Removal
0.5 Uniform Ceiling, 90% Removal
0.2 Floor, 1.2 Ceiling

Figure 2-16
Western Coal Shipped East, 1995
Higher FGD Costs

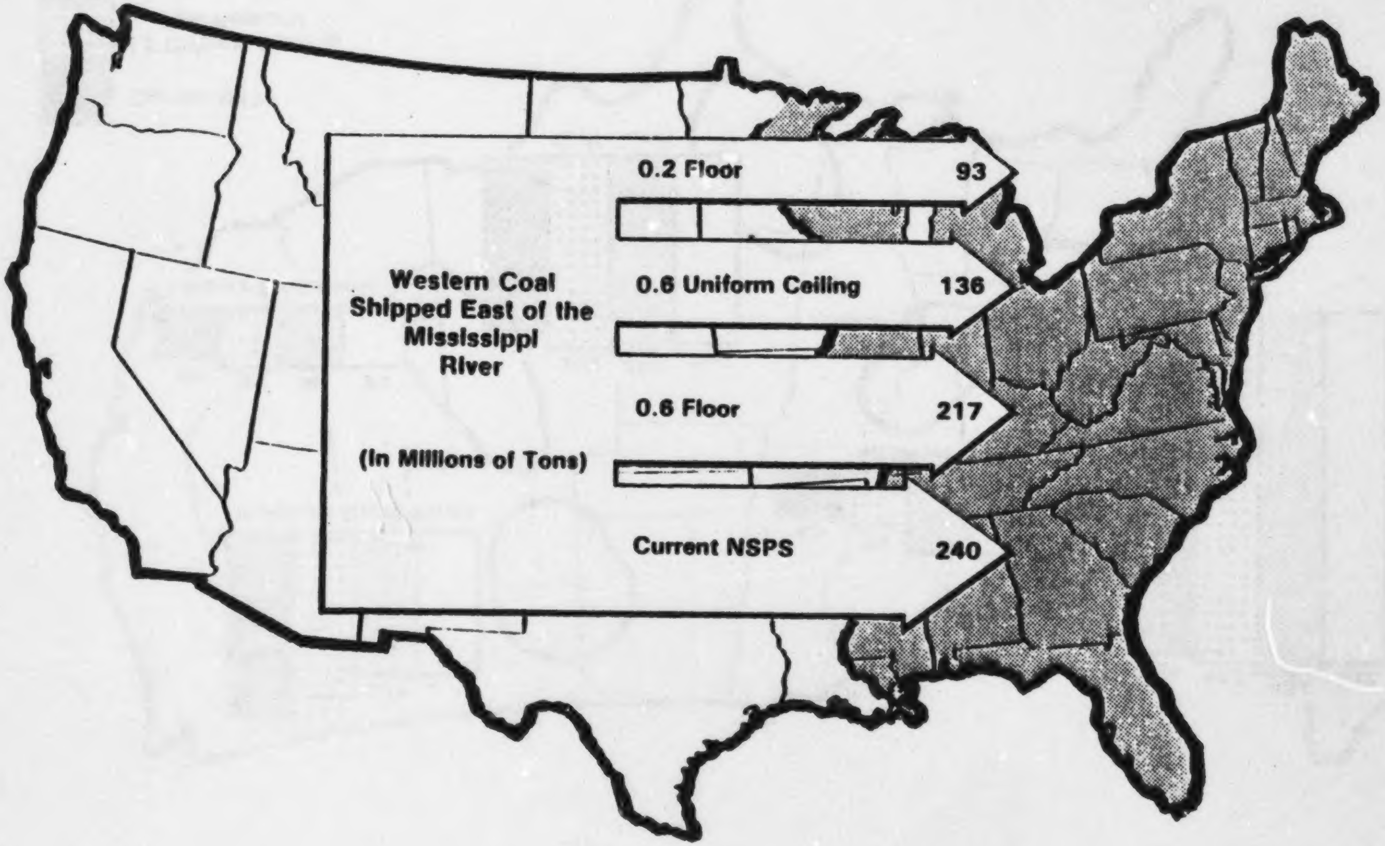
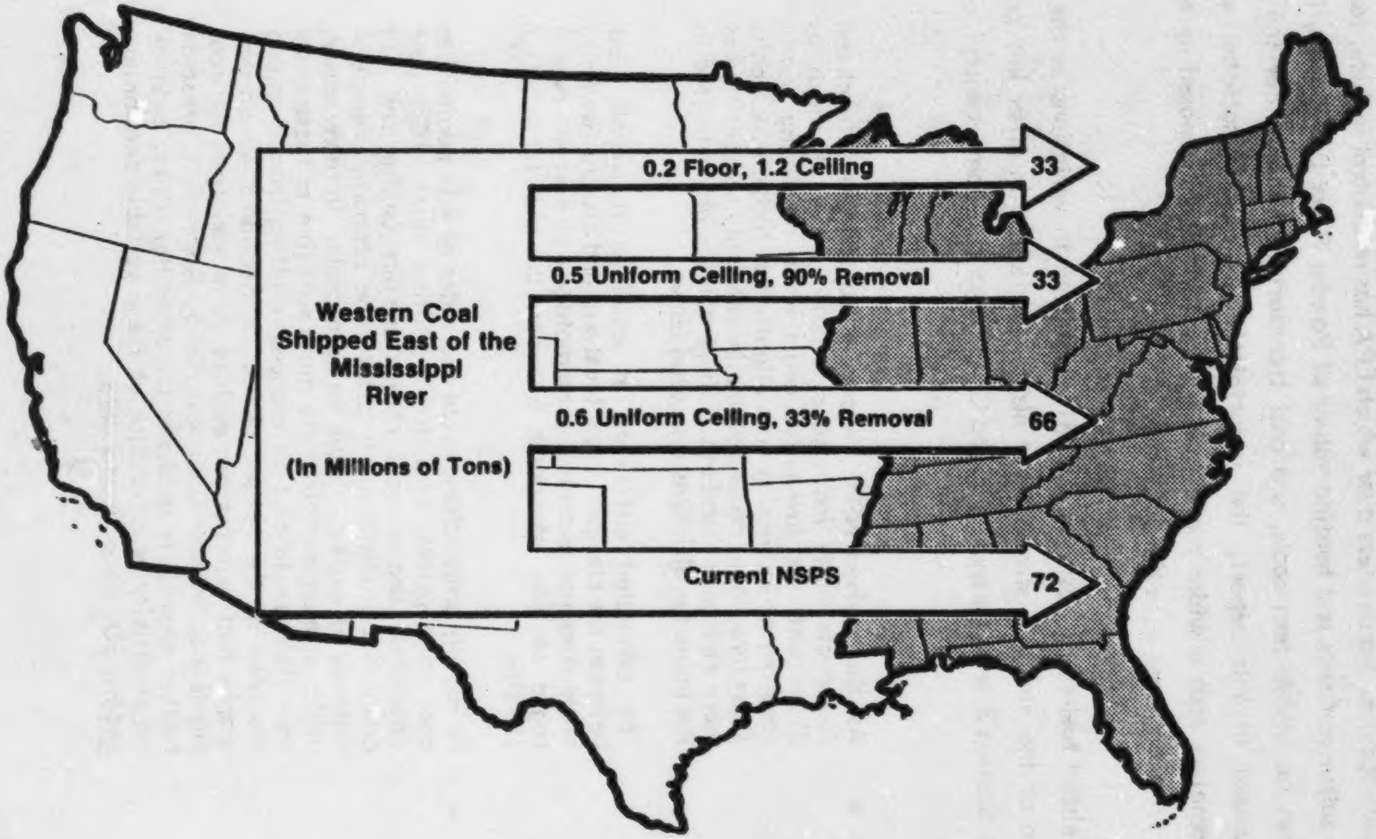

Western Coal
Shipped East of the
Mississippi
River
(In Millions of Tons)
0.2 Floor
93
0.6 Uniform Ceiling
136
0.6 Floor
217
Current NSPS
240

Figure 2-17
Western Coal Shipped East, 1995
Lower FGD Costs


Western Coal
Shipped East of the
Mississippi
River
(In Millions of Tons)
0.2 Floor, 1.2 Ceiling
33
0.5 Uniform Ceiling, 90% Removal
33
0.6 Uniform Ceiling, 33% Removal
66
Current NSPS
72

greater than the range of cost increases expected with the more stringent RNSPS options. Parameters over which EPA has no control include, for example, the sulfur contents and heating values of Powder River Basin coals, f.o.b. mine prices for midwestern coals, and coal transportation rates. For the key cities discussed in this report, the uncertainties in costs associated with these parameters span a wider range than the cost increases imposed by selecting a full scrubbing over a partial scrubbing option.

Levelized fuel-cycle costs are sensitive not only to variations in the level and form of the emission standard but also to variations in other key parameters. (See Section 3 and Appendixes B and C for details.) Some general conclusions are:

- As the revised NSPS become more stringent, levelized fuel-cycle costs increase substantially (by as much as 25 percent) for low-sulfur coals while remaining nearly constant or increasing only slightly for high-sulfur coals. Therefore, local coals become increasingly competitive at more stringent standards. These effects are reflected in the impact projections discussed above.

- The estimated difference in levelized fuel-cycle cost between the cheapest local (eastern) and distant (western) coals does not exceed approximately ± 15 percent over a range of SO_2 standards between 0.2 and 1.2 lb $SO_2/10^6$ Btu.

- Relatively small changes (on the order of ± 10 percent) in coal mine prices, coal transportation rates, FGD cost estimates, and/or coal characteristics (sulfur and Btu content) can significantly affect the economic competitiveness of eastern versus western coals. In many cases, utility economic choices are more sensitive to these costs than they are to cost differences resulting from changing the level of the revised NSPS. In Section 3 we present graphs that demonstrate each of these variations for coal plants located near Columbus, Ohio. Appendix C presents further sensitivity analyses for other key cities, examining sensitivity as a function of these variable parameters and the SO_2 emission standard.

Distinguishing Differences among the Impacts of Various Partial Scrubbing Options

- The impacts of many of the very similar partial scrubbing options investigated in other analyses[8] are, in practice, indistinguishable, because of the uncertainties in future costs likely to be faced by individual utilities in each state. Many of the myriad numbers presented for similar standards at EPA's December 12th hearings are, in fact, overlapping results that add little to the ability to choose between feasible options.

The Implications and Reliability of Cost-Effectiveness Measures

Cost per ton of SO_2 removed is not definitive as a cost-effectiveness measure for comparing alternative standards. This is because (a) it changes rapidly as a function of the required level of emissions, and (b) uncertainties are introduced by aggregating this measure across many different coals and power-plant situations. This cost-effectiveness measure and the companion measures of cost per kWh and cost per Btu of fuel input are discussed and illustrated graphically in Section 3.

The Implications of Lower versus Higher Future FGD Costs

As previously indicated, the FGD capital and operating cost estimates supplied in December 1978 by the Tennessee Valley Authority are substantially lower than PEDCo's. (See Appendix A for details.) These differences reflect different engineering cost criteria and degrees of conservatism in cost estimation. Either set of estimates could be used to describe future FGD costs under different utility situations. Previous RNSPS studies have used PEDCo costs. Some important comparisons are:

- For lime FGD systems, TVA's capital costs are about 30 percent lower than PEDCo's, and TVA's operating costs are 20 percent lower. For limestone systems, TVA's capital and operating costs are about 40 percent and 27 percent lower, respectively.

In general, lower FGD costs relative to higher FGD costs will:

- Increase the attractiveness of local coals and increase the projected amount of scrubbing for any partial scrubbing option. The amounts of scrubbing mandated under the full scrubbing option are very similar under both sets of costs.
- Reduce dramatically projected shipments of western coal to the East.
- Reduce projected generation and therefore projected SO_2 emissions from existing plants in the East (because of relatively cheaper operating costs for new plants under lower as compared with higher FGD costs).
- Reduce the projected differences between full and partial scrubbing options.

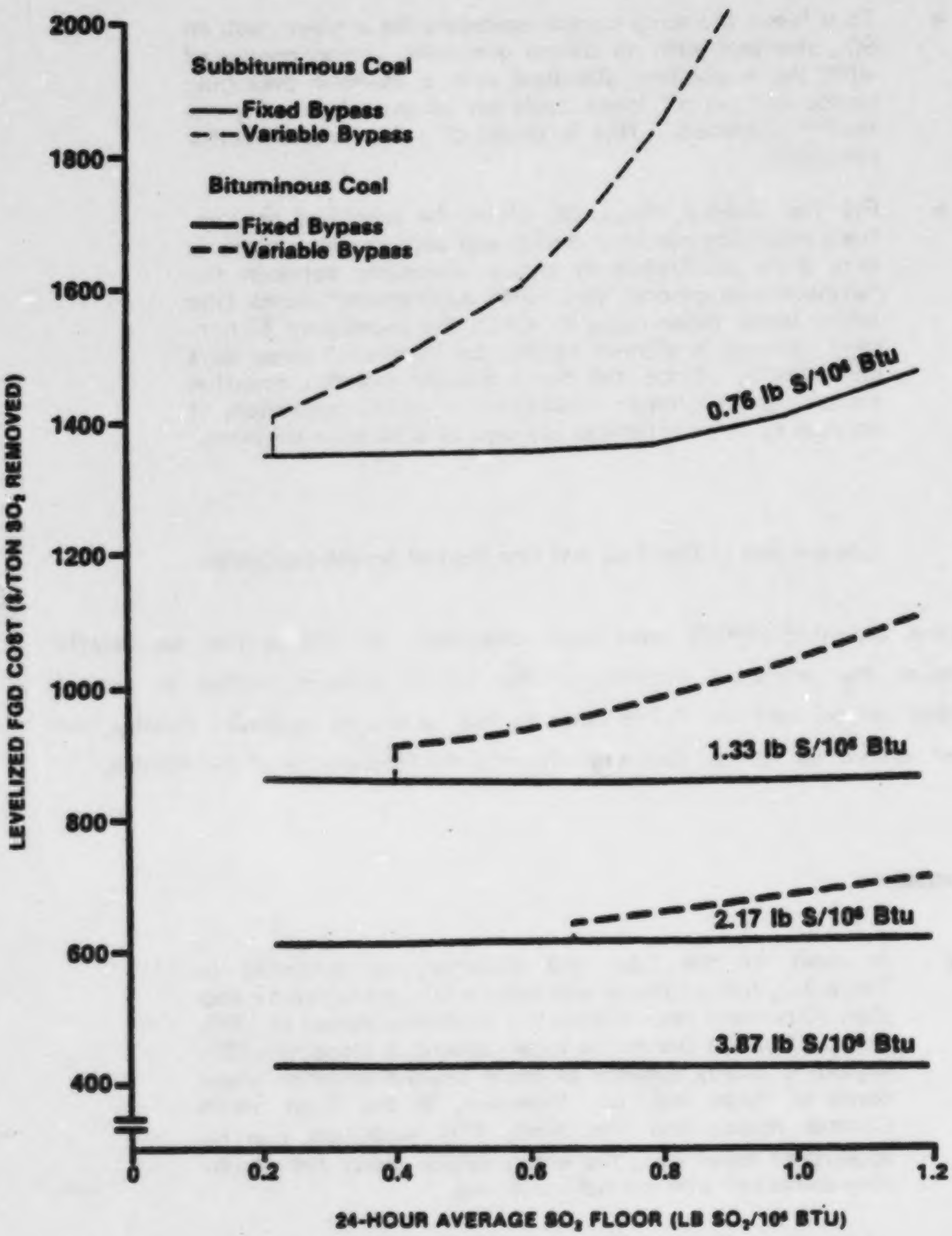
The two different ranges of impacts defined by the forecasts using the TVA and PEDCo costs can be interpreted as bounding the most likely impacts of the RNSPS. They also reflect the other uncertainties investigated in the sensitivity studies.

The Form of the Revised Standard

The form and technical requirements of any given standard have important implications for pollution control costs. Some general conclusions include the following:

- Variable bypass on FGD scrubbers is less cost effective than fixed bypass for emission control. (See Figure 2-18.)
- For the same annual emission level, an annual average or 30-day standard compared with a 24-hour standard permits greater FGD gas bypass for a given coal and results in lower energy penalties. All standards were evaluated assuming a constant SO_2 removal efficiency, i.e., fixed bypass. However, short-term emissions resulting from coal sulfur variability may be higher than the annual average. This likelihood and the diurnal nature of adverse air pollution episodes indicate the need for setting appropriate 24-hour standards in conjunction with the longer-term standards.

Figure 2-18
Comparison of FGD Cost Effectiveness per Ton of SO_2 Removed under 24-Hour Average SO_2 Control Alternatives with a 1.2 lb/10^6 Btu Ceiling



- Setting an annual or 30-day standard specified as a uniform ceiling with no mandatory percentage removal requirement results in equivalent emissions from all power plants regardless of the quality of the coal burned. All other forms of the standard result in emissions that depend on the sulfur and Btu content and sulfur variability of the coal burned.

- To achieve the same annual emissions for a given coal, an SO_2 standard with an annual averaging period compared with the equivalent standard with a 24-hour averaging period will permit lower costs per kilowatt-hour of electricity produced. This is principally due to coal sulfur variability.

- For the 24-hour standards, given the specified assumptions regarding scrubber design and performance, there is very little difference in annual emissions between the "without exemptions" and "with exemptions" cases (the latter being those cases in which the mandatory 85 percent removal is allowed to drop to 75 percent three days per month). Since the three-day-per-month exemption should permit greater flexibility in utility operation, it appears to be an effective element of a 24-hour standard.

Comparison of One Full and One Partial Scrubbing Option

Numerous potential RNSPS have been analyzed. In this section we briefly summarize the projected impacts of the 0.6 lb uniform ceiling (a partial scrubbing option) and the 0.2 lb floor (a full scrubbing option). Finally, we mention some other factors that will influence the final choice of the RNSPS.

SO_2 Emissions

- In most of the East and Midwest, as indicated in Table 2-1, full scrubbing will reduce SO_2 emissions by less than 10 percent over the partial scrubbing option in 1995. This is primarily due to the large amount of remaining SIP-regulated plants subject to more lenient emission standards in these regions. However, in the West South Central region and the West, SO_2 emissions can be 25 percent lower over the entire region under full scrubbing compared with partial scrubbing.

Table 2-1

Percentage SO_2 Emission Reduction in 1995 under Full Scrubbing Compared with Partial Scrubbing[a]

	Higher FGD Costs	Lower FGD Costs[b]
National	8.0%	4.3%
East	7.2%	1.8%
Midwest	3.0%	3.4%
West South Central	22.3%	9.6%
West	25.6%	20.4%

[a] Full scrubbing: 0.2 lb floor. Partial scrubbing: 0.6 lb uniform ceiling.

[b] Using lower rather than higher FGD costs reduces absolute emission levels under all RNSPS because FGD usage is relatively less expensive. Thus, the relative emission differences are smaller.

- Regional aggregations belie the local emission changes that can occur. Figures 2-19, 2-20, and 2-21 show the changes in projected emissions at the county level for three groupings of states. Note that large percentage differences occur in a number of counties in western states and in the West South Central region. While percentage change is not the definitive measure of analysis and should not be relied upon exclusively, it nonetheless illustrates relative local variations between full and partial scrubbing.

  It should also be noted that, compared with partial scrubbing, full scrubbing can lead to greater emissions in some counties. This can occur as the result, under full scrubbing, of selecting a coal of much higher sulfur content than would be used under partial scrubbing or of operating SIP-regulated units at slightly higher capacity factors. In most counties, however, the emission differences between full and partial scrubbing are less than ten percent.

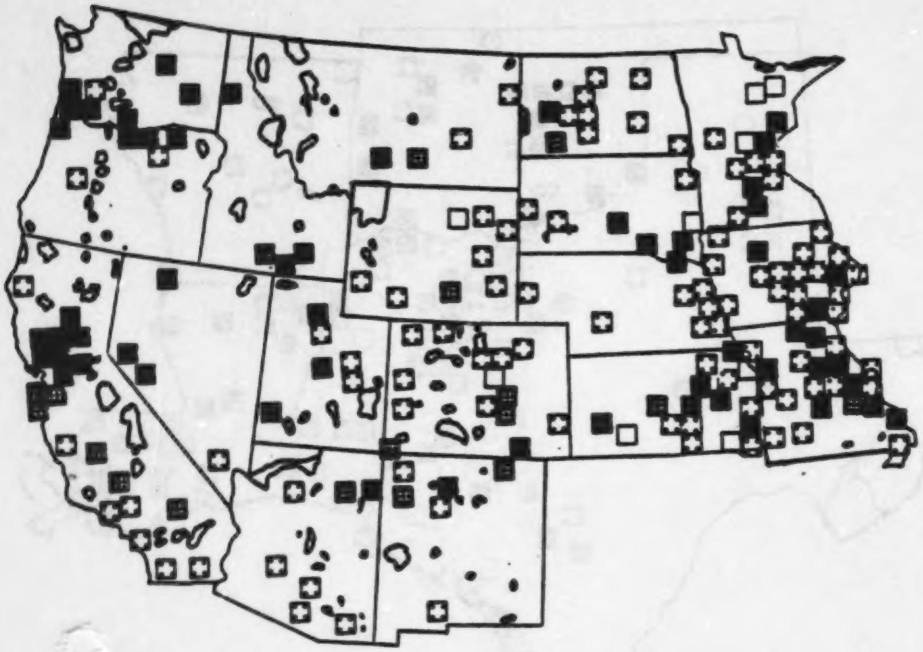
- SO_2 emissions from RNSPS plants regulated by a full scrubbing standard can be less than half of those from RNSPS plants under a partial scrubbing standard. Because emissions from SIP-regulated plants dominate total emissions over the 1985-2000 period, the difference between full and partial scrubbing will become more significant as these older plants are retired. Differences will also be greatest in those regions that do not currently have large amounts of coal generating capacity.

- If a partial scrubbing option were adopted now (which would affect plants coming on line after 1982) and a full scrubbing option were implemented four years from now for plants coming on line after 1987, SO_2 emissions in the year 2000 in the western U.S. would be 8 to 10 percent higher than if a full scrubbing option were adopted now.

Economic Costs

- Under the full scrubbing option, cumulative pollution control investment is 21 percent higher than under partial scrubbing if the higher FGD cost estimates for wet scrubbing processes are used, but only 8 percent if the lower estimates are used. The use of dry scrubbing technologies would probably reduce the differentials between the costs of full and partial scrubbing.

Figure 2-19
Percentage Change in Power-Plant SO_2 Emissions in 1995: Partial vs. Full Scrubbing
West North Central and Mountain and Pacific Regions



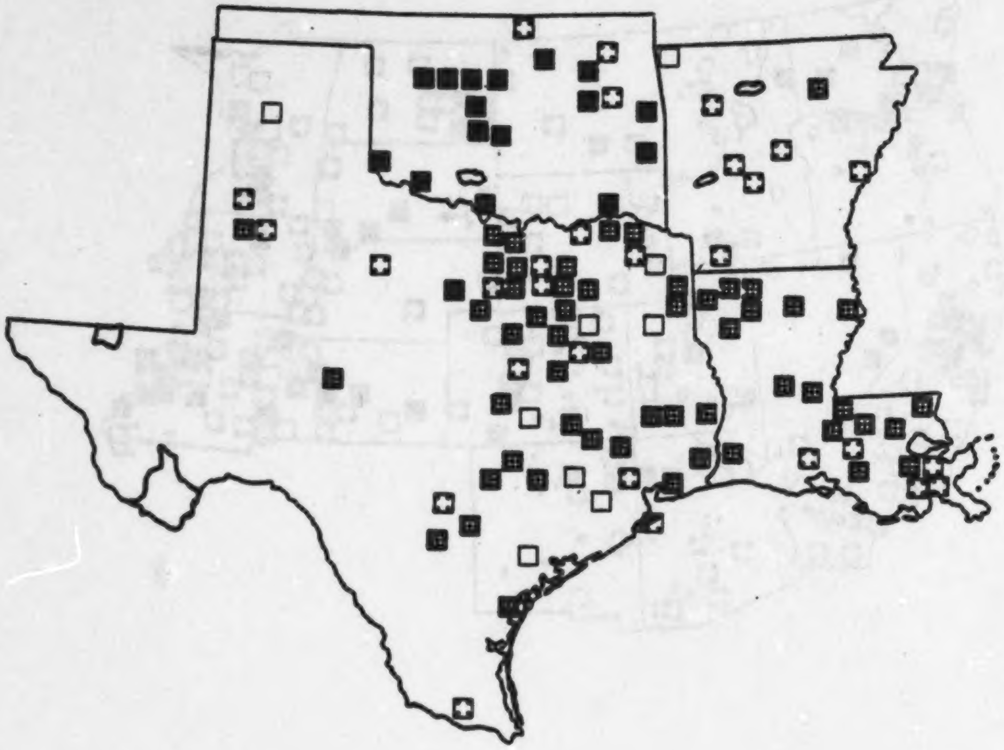
Each square represents a county with SO_2 emission changes.

$$\text{Percentage Change} = \left(\frac{\text{Partial - Full}}{\text{Full}}\right)$$

- ■ >110%
- ▨ 10— 110%
- ⊞ -10% — +10%
- ☐ <-10%
- ◌ Class I Areas

Partial Scrubbing: 0.6 lb $SO_2/10^6$ Btu annual ceiling, 33% minimum removal.
Full Scrubbing: 0.63 lb $SO_2/10^6$ Btu annual ceiling, 90% minimum removal.

Figure 2-20
Percentage Change in Power-Plant SO_2 Emissions in 1995: Partial vs. Full Scrubbing
West South Central Region



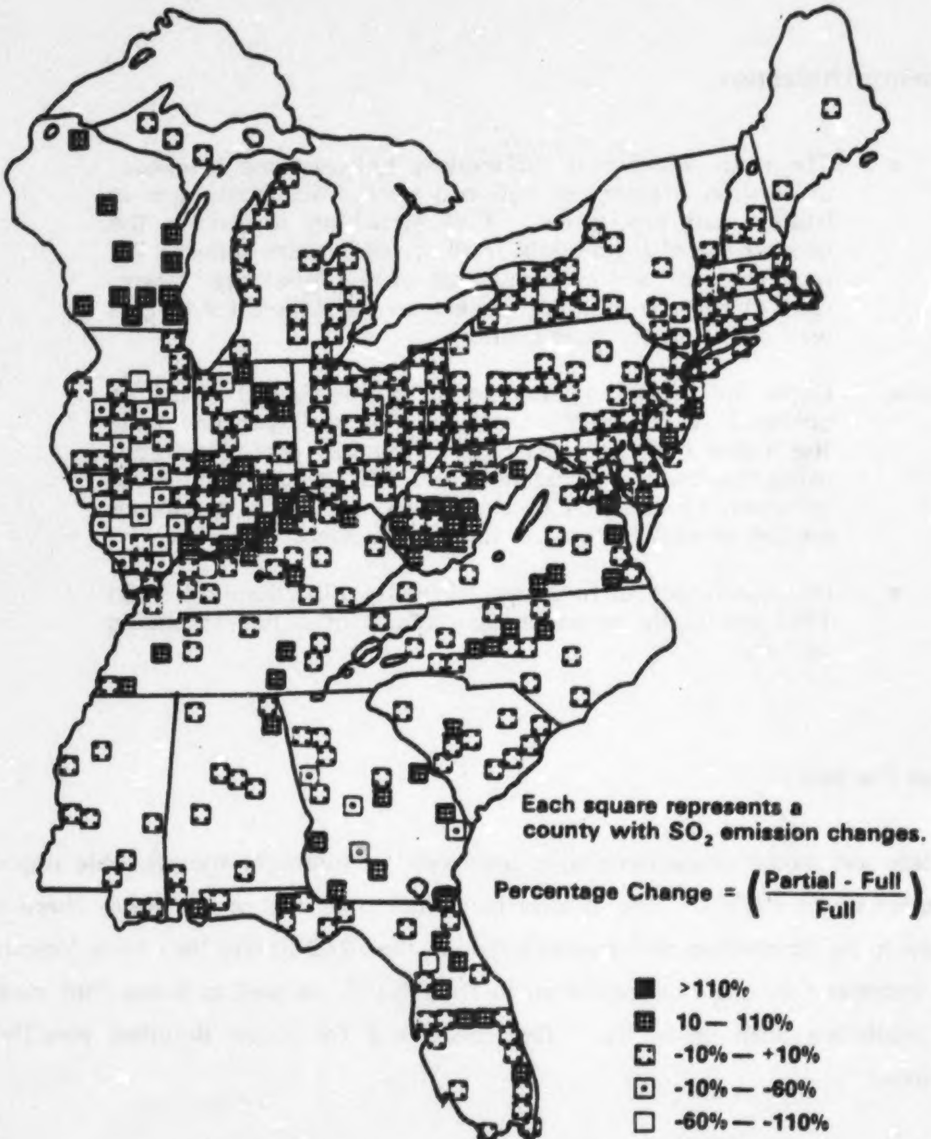
Each square represents a county with SO_2 emission changes.

$$\text{Percentage Change} = \left(\frac{\text{Partial - Full}}{\text{Full}}\right)$$

- ■ >110%
- ▦ 10 — 110%
- ⊞ -10% — +10%
- □ <-10%
- Class I Areas

Partial Scrubbing: 0.6 lb $SO_2/10^6$ Btu annual ceiling, 33% minimum removal.
Full Scrubbing: 0.63 lb $SO_2/10^6$ Btu annual ceiling, 90% minimum removal.

Figure 2-21
Percentage Change in Power-Plant SO_2 Emissions in 1995: Partial vs. Full Scrubbing
East North Central, East, and East South Central Regions


Each square represents a county with SO_2 emission changes.
Percentage Change = $\left(\frac{\text{Partial - Full}}{\text{Full}}\right)$
■ >110%
▦ 10 — 110%
☐ -10% — +10%
☐ -10% — -60%
☐ -60% — -110%
○ Class I Areas

Partial Scrubbing: 0.6 lb $SO_2/10^6$ Btu annual ceiling, 33% minimum removal.
Full Scrubbing: 0.63 lb $SO_2/10^6$ Btu annual ceiling, 90% minimum removal.

- National average monthly electricity bills vary by less than 2 percent between the full and partial scrubbing options using the higher FGD cost assumptions, and by less than 1 percent using the lower FGD cost assumptions.
- The present value of total utility expenditures varies less than 1 percent between the full and partial scrubbing options.

Resource Utilization

- The most significant differences between the resource utilization impacts of full and partial scrubbing are in utility coal production. Full scrubbing results in the greater use of local coals. Full scrubbing also reduces the movement of western coal east of the Mississippi River. Coal markets will clearly depend on the RNSPS for SO_2 as well as future scrubber costs.
- Under full scrubbing, compared to this partial scrubbing option, FGD capacity increases by about 16 percent using the higher FGD cost assumptions, and by about 9 percent using the lower cost assumptions. FGD sludge production increases by about 21 percent under the full scrubbing as compared with the partial scrubbing option.
- No significant differences in utility oil consumption in 1995 are likely to occur as a result of a full scrubbing option.

Other Factors

Models and model projections have been used to highlight the probable impacts of alternative RNSPS. The results have indicated the areas where there are likely to be observable differences between the RNSPS, and they have indicated the impacts that are most sensitive to the RNSPS, as well as those that cannot be projected with certainty. (See Section 3 for more detailed sensitivity studies.)

Exogenous factors such as the rate of growth and acceptance of nuclear power, the availability of gas for electricity generation, the availability of oil, and the growth in electricity demand will significantly influence the impacts of any RNSPS.

Obviously, other factors also will bear on the selection of a revised NSPS. Some of these are listed below in two categories of questions: questions of technological capability, and questions of political feasibility.

Questions of Technological Capability

a. Will scrubbers perform reliably at the levels required for full scrubbing?

b. Can dry scrubbing technologies significantly reduce the costs of scrubbing lower-sulfur coals?

c. Will greater coal sulfur variability than assumed in these analyses necessitate using higher percentage removals or lower-sulfur coals in order to meet 24-hour-average standards?

d. Will emission-monitoring devices adequately measure compliance with the proposed RNSPS?

e. Is the flexibility of utility operation significantly greater for longer averaging times (e.g., 30 days instead of daily)? What benefits would result from longer averaging times? What disbenefits?

Questions of Political Feasibility

a. How will "local coals" be defined under Section 125 of the 1977 Clean Air Act Amendments? Will this definition influence the availability of lower-sulfur coals for use under a partial scrubbing option?

b. What are the employment implications of full versus partial scrubbing?

c. How will full versus partial scrubbing affect visibility in pristine areas of the West?

d. What regional air quality impacts will result from full versus partial scrubbing?

e. What, if any, inflationary impacts can be expected to result from the RNSPS?

f. Will the usable reserve base of U.S. coals be affected by the choice of RNSPS?

g. How will the new SIPs to be implemented after 1979 affect electric utility operations? What are the expected lifetimes of SIP-regulated plants?

h. How will PSD and non-attainment provisions of the Clean Air Act (1977) influence required emission limits?

Answers to these questions will be discussed and debated during the period prior to selecting a revised NSPS.

3. KEY QUESTIONS AND ANSWERS

This section discusses in detail the results of the sensitivity studies in order to answer critical questions pertinent to the selection of a revised New Source Performance Standard for SO_2. The appendixes contain additional information.

I. WHAT ARE THE LIKELY IMPACTS OF A REVISED NSPS?

a. HOW WILL NATIONAL COSTS AND SO_2 EMISSION REDUCTIONS, BASED ON THE HIGHER (PEDCO) FGD COSTS, BE DISTRIBUTED REGIONALLY IN 1995 FOR THE FULL SCRUBBING OPTION (0.2 LB FLOOR) AND THE PARTIAL SCRUBBING OPTIONS (0.6 LB FLOOR and 0.6 LB UNIFORM CEILING)?

In 1995, national utility SO_2 emissions drop from 22.8 million tons projected under the current NSPS to 19.9 million tons (12.7 percent reduction) under the 0.6 lb uniform ceiling, 18.8 million tons (17.5 percent reduction) under a 0.6 lb floor, and 18.3 million tons (19.7 percent reduction) under a 0.2 lb floor. Total utility costs increase over those of the current NSPS by about 2.9 percent, 4.4 percent, and 5.2 percent for the uniform ceiling, 0.6 lb floor, and 0.2 lb floor, respectively. The percentage changes shown in Table 3-1 indicate some significant regional differences. These differences were illustrated earlier in Figures 2-9 through 2-11. Regional SO_2 emissions were illustrated in Figure 2-2.

In the West South Central region, where a considerable amount of new coal-fired capacity can be anticipated as a result of the phasing out of natural gas as a boiler fuel, emissions are expected to decrease by as much as 44 percent while costs increase by 15 percent. In the Mountain and Pacific regions, the combined SO_2 emission reduction will be about 37 percent under a full scrubbing option, 28 percent under the 0.6 lb floor, and 16 percent under the 0.6 lb uniform ceiling. Cost increases in the Mountain and Pacific Regions will be about 7 percent,

Table 3-1

Full and Partial Scrubbing vs. Current NSPS: Percentage Changes in Regional SO_2 Emissions and Total Utility Costs in 1995[a]

Census Regions	0.2 lb Floor[b] (Full Scrubbing)			0.6 lb Floor[b] (Partial Scrubbing)			0.6 lb Uniform Ceiling[c] (Partial Scrubbing)		
	SO_2 Emission Reduction (%)	Cost Increase (%)	Ratio	SO_2 Emission Reduction (%)	Cost Increase (%)	Ratio	SO_2 Emission Reduction (%)	Cost Increase (%)	Ratio
Nation	19.7	5.2	3.8	17.5	4.4	4.0	12.7	2.9	4.4
Northeast[d]	20.0	1.0	20.0	20.4	1.0	20.4	13.7	1.0	13.7
Southeast[e]	17.9	2.3	7.8	17.6	3.0	5.9	12.6	1.8	7.0
North Central[f]	7.5	4.8	1.6	4.3	5.0	0.9	5.2	2.7	1.9
West South Central	44.2	14.7	3.0	42.0	9.3	4.5	28.2	6.5	4.3
Mountain	21.9	6.0	3.7	16.0	4.5	3.6	10.3	3.4	3.0
Pacific	55.0	7.4	7.4	41.5	5.6	7.4	21.7	4.6	4.7

[a] These results reflect the higher (PEDCo) FGD costs.

[b] 1.2 lb $SO_2/10^6$ Btu daily ceiling with exemptions; 90 percent removal with specified 24-hour floor.

[c] Annual average SO_2 emission ceiling of 0.6 lb $SO_2/10^6$ Btu.

[d] New England and Middle Atlantic Census Region states.

[e] South Atlantic and East South Central Census Region states.

[f] East North Central and West North Central Census Region states.

5 percent, and 4 percent under the three options respectively. The emission reduction can be as large as 55 percent in the Pacific Region under a full scrubbing option or 22 percent under the 0.6 lb uniform ceiling.

b. THE REGIONAL EMISSION PROJECTIONS INCLUDE EMISSIONS FROM BOTH OLD AND NEW GENERATING UNITS. THE REVISED NSPS WILL AFFECT ONLY THOSE UNITS IN OPERATION AFTER 1982, AND THESE PLANTS AND THEIR SUCCESSORS SHOULD BE OPERATING FOR OVER 35 YEARS AFTER 1983. WHAT ARE THE DIFFERENCES IN EMISSIONS FROM THESE RNSPS PLANTS COMPARED WITH THE OLDER UNITS SUBJECT TO MORE LENIENT STANDARDS?

Table 3-2 and Figure 2-3 indicate the distribution of emissions from plants regulated under State Implementation Plan standards, under the current NSPS, and under three alternative RNSPS. It can be seen that, when scrubbing is required for RNSPS plants, the older SIP plants may be operated at slightly increased loads over the baseline case. However, the older SIP plants are going to be retired over time; and, increasingly, a greater fraction of emissions will come from RNSPS plants. It is estimated that in 1995, for example, under the current NSPS, 6.7 million tons of SO_2 (30 percent of national SO_2 emissions) will come from RNSPS plants.

The 0.6 lb uniform ceiling option reduces SO_2 emissions from RNSPS plants in 1995 by 2.8 million tons (42 percent), resulting in RNSPS plant emissions of 3.9 million tons, or 20 percent of national SO_2 emissions. Another partial scrubbing option (0.6 lb floor) reduces emissions from the RNSPS plants in 1995 by 4.6 million tons (68 percent), resulting in RNSPS plant emissions of 2.2 million tons, or 11 percent of national SO_2 emissions. A full scrubbing option reduces RNSPS plant emissions by 4.8 million tons (71 percent), bringing SO_2 emissions from these plants down to 1.9 million tons, or 10 percent of national emissions. In other words, under a full scrubbing option, RNSPS plants will emit half the SO_2 they would emit under the 0.6 lb uniform ceiling. These reductions have regional and longer-term implications:

Table 3-2

National Coal-Fired, Power-Plant SO_2 Emissions by Regulatory Category (million U.S. tons per year)[a]

Year	Current NSPS for RNSPS Units			0.6 lb Floor for RNSPS Units[b]			0.2 lb Floor for RNSPS Units[c]			0.6 lb Uniform Ceiling for RNSPS Units[d]		
	SIP Units[e]	NSPS Units[f]	RNSPS Units[g]	SIP Units[e]	NSPS Units[f]	RNSPS Units[g]	SIP Units[e]	NSPS Units[f]	RNSPS Units[g]	SIP Units[e]	NSPS Units[f]	RNSPS Units[g]
1985	14.3	1.52	0.97	14.4	1.51	0.29	14.5	1.51	0.25	14.3	1.51	0.51
1990	13.6	1.54	3.92	13.9	1.54	1.26	13.9	1.53	1.10	13.7	1.53	2.19
1995	13.1	1.50	6.74	13.7	1.52	2.15	13.5	1.51	1.94	13.1	1.51	3.9

[a] These results reflect the higher (PEDCo) FGD Costs.

[b] 1.2 lb $SO_2/10^6$ Btu daily ceiling, 85 percent daily removal, 0.6 lb floor, partial scrubbing allowed.

[c] Full scrubbing (same as 0.6 lb floor above but with 0.2 lb floor).

[d] Uniform ceiling: (0.6 lb $SO_2/10^6$ Btu annual ceiling, 33 percent minimum SO_2 removal requirement, partial scrubbing allowed).

[e] Units regulated under State Implementation Plans.

[f] Units regulated under the current NSPS (1.2 lb $SO_2/10^6$ Btu, annual ceiling).

[g] Post-1982 units regulated under a revised NSPS (RNSPS).

- In 1995 in the East, average RNSPS coal-plant SO_2 emissions under a 0.6 lb uniform ceiling reach 0.6 lb $SO_2/10^6$ Btu, as expected, compared with 0.36 lb $SO_2/10^6$ Btu under the 0.2 lb floor standard (which requires 90 percent annual removal)

- In 1995 in the West South Central region, average RNSPS plant emissions would rise from 0.29 lb $SO_2/10^6$ Btu under a 0.2 lb floor standard, to 0.34 lb $SO_2/10^6$ Btu under a 0.6 lb floor standard, to 0.6 lb $SO_2/10^6$ Btu under a uniform 0.6 lb ceiling

- In 1995 in the West, average RNSPS plant emissions rise from 0.16 lb $SO_2/10^6$ Btu under a 0.2 lb floor standard, to 0.34 lb $SO_2/10^6$ Btu under a 0.6 lb floor standard, to 0.6 lb $SO_2/10^6$ Btu under the 0.6 lb uniform ceiling

c. WHAT ARE THE EMISSION PROJECTIONS FOR COAL-FIRED PLANTS WHEN THE LOWER (TVA) FGD COST ESTIMATES ARE USED?

The results in Table 3-2 were obtained using the higher (PEDCo) scrubber cost estimates. Table 3-3 shows results for the current NSPS and the 0.2 lb floor (full scrubbing) standard using the lower (TVA) FGD cost estimates.* Several principal differences between the higher and lower FGD cost scenarios are observed:

- For any year, the lower FGD cost estimates reduce the costs of operating RNSPS units with scrubbers. Thus, under the lower FGD cost scenarios, RNSPS units will be used to generate a greater fraction of the total electricity produced. RNSPS emissions in any year will be greater under the TVA scenarios, both because more generation occurs in these plants and because, on the average, higher-sulfur coals are burned. However, in several cases SO_2 emissions will be lower overall than under the higher FGD cost scenarios, because existing units subject to more lenient SIP standards will be operated less. See Figure 3-1 as compared with Figure 2-3.

- Lower FGD costs reduce the emission differences between full and partial scrubbing options.

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* A brief explanation of the engineering differences between PEDCo's and TVA's cost estimates is presented in Appendix A.

Table 3-3

National Coal-Fired, Power-Plant SO_2 Emissions by Regulatory Category (million U.S. tons per year)[a]

Year	Current NSPS for RNSPS Units			0.2 lb Floor for RNSPS Units[b]		
	SIP Units[c]	NSPS Units[d]	RNSPS Units[e]	SIP Units[c]	NSPS Units[d]	RNSPS Units[e]
1985	13.9	1.65	1.05	14.2	1.65	0.35
1990	12.9	1.67	4.07	12.9	1.67	1.66
1995	11.8	1.64	7.13	11.7	1.64	3.07

[a] These results reflect the lower (TVA) FGD Costs.

[b] Full scrubbing (1.2 lb $SO_2/10^6$ Btu daily ceiling, 85 percent minimum daily SO_2 removal, 0.2 lb floor).

[c] Units regulated under State Implementation Plans.

[d] Units regulated under the current NSPS (1.2 lb $SO_2/10^6$ Btu).

[e] Post-1982 units regulated under a revised NSPS (RNSPS).

Figure 3-1

National SO_2 Emissions from Coal-Fired Power Plants, 1995

Lower FGD Costs

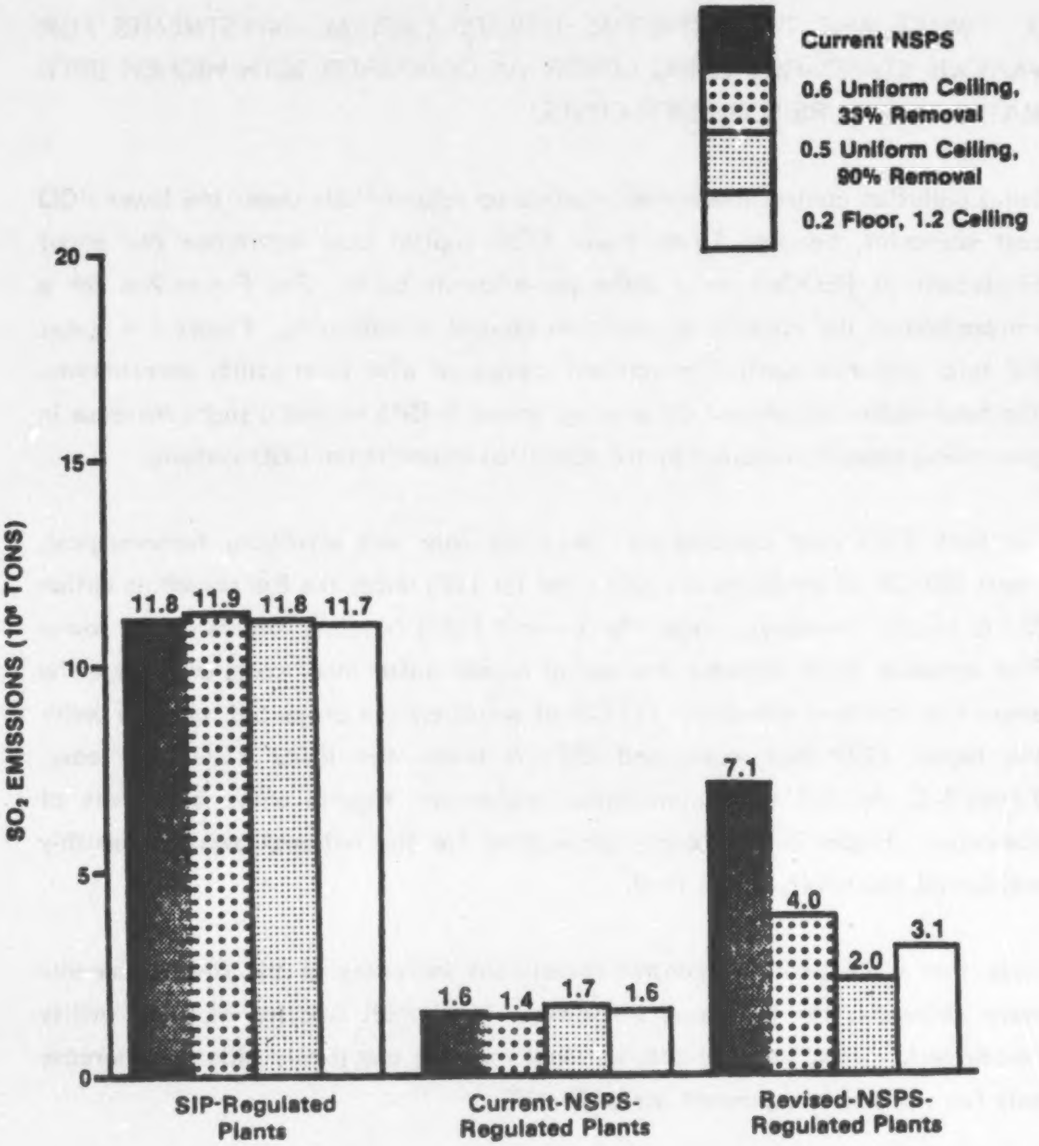

Table 3-4 indicates regional cost and emission differences expressed as a percentage change from the current NSPS baseline. Figure 3-2 shows regional SO_2 emissions for various RNSPS under the lower cost estimates for FGD. Figure 3-3 shows the national cost changes associated with lower FGD costs and should be compared with Figure 2-8.

d. WHAT ARE THE PRINCIPAL UTILITY CAPITAL INVESTMENTS FOR VARIOUS STANDARDS USING LOWER AS COMPARED WITH HIGHER ESTIMATES OF FUTURE SCRUBBER COSTS?

Total pollution control investment costs drop substantially under the lower FGD cost scenarios, because TVA's lower FGD capital cost estimates are about 57 percent of PEDCo's on a dollar-per-kilowatt basis. See Figure 2-6 for a comparison of the cumulative pollution control investments. Figure 3-4 shows the total pollution control investment compared with total utility investments. The total utility investment differences across RNSPS reflect a slight increase in generating capacity required by the operation of additional FGD systems.

For both FGD cost calculations (assuming only wet scrubbing technologies), about 320 GW of scrubbers are projected for 1995 under the full scrubbing option (0.2 lb floor). However, under the current NSPS baseline standard, the lower TVA scrubber costs increase the use of higher-sulfur local coals and hence the amount of scrubber capacity: 133 GW of scrubbers are projected for 1995 under the higher FGD cost case, and 201 GW under the lower FGD cost case. Tables 3-5 and 3-6 show cumulative investment figures under both sets of scenarios. Figure 2-7 compares projections for the national average monthly residential electricity bill in 1995.

Note that while pollution control investment increases as the RNSPS become more stringent, the increased investment is a small fraction of total utility investment. Thus, for example, national monthly electricity bills will increase only from two to five percent across RNSPS.

Table 3-4

Full and Partial Scrubbing vs. Current NSPS: Percentage Changes in Regional SO_2 Emissions and Total Utility Costs in 1995[a]

Census Regions	0.2 lb Floor[b] (Full Scrubbing)			0.6 lb Uniform Ceiling[c] (Partial Scrubbing)			0.5 lb Ceiling[d] (Partial Scrubbing)		
	SO_2 Emission Reduction (%)	Cost Increase (%)	Ratio	SO_2 Emission Reduction (%)	Cost Increase (%)	Ratio	SO_2 Emission Reduction (%)	Cost Increase (%)	Ratio
Nation	19.1	2.8	6.8	15.5	2.3	6.7	23.6	3.2	7.4
Northeast[e]	15.2	1.0	15.2	16.7	1.0	16.7	22.2	1.0	22.2
Southeast[f]	14.9	2.3	6.5	12.5	2.0	6.3	17.7	1.0	17.7
North Central[g]	13.5	3.0	4.5	9.8	2.6	3.8	17.8	3.5	5.1
West South Central	39.1	4.0	9.8	32.6	2.7	12.1	46.5	4.9	9.5
Mountain	20.0	5.8	3.4	22.3	3.3	6.8	22.3	6.3	3.5
Pacific	49.4	4.6	10.7	10.9	3.6	3.0	55.5	4.9	11.3

[a] These results reflect the lower (TVA) FGD costs.

[b] 1.2 lb $SO_2/10^6$ Btu daily ceiling with exemptions; 90 percent removal with specified 24-hour floor.

[c] Uniform ceiling: 0.6 lb $SO_2/10^6$ Btu annual ceiling, 33 percent minimum SO_2 removal requirement.

[d] Annual average SO_2 emission ceiling of 0.5 lb $SO_2/10^6$ Btu.

[e] New England and Middle Atlantic Census Region states.

[f] South Atlantic and East South Central Census Region states.

[g] East North Central and West North Central Census Region states.

Figure 3-2
Regional SO_2 Emissions (10^6 Tons), 1995
Lower FGD Costs

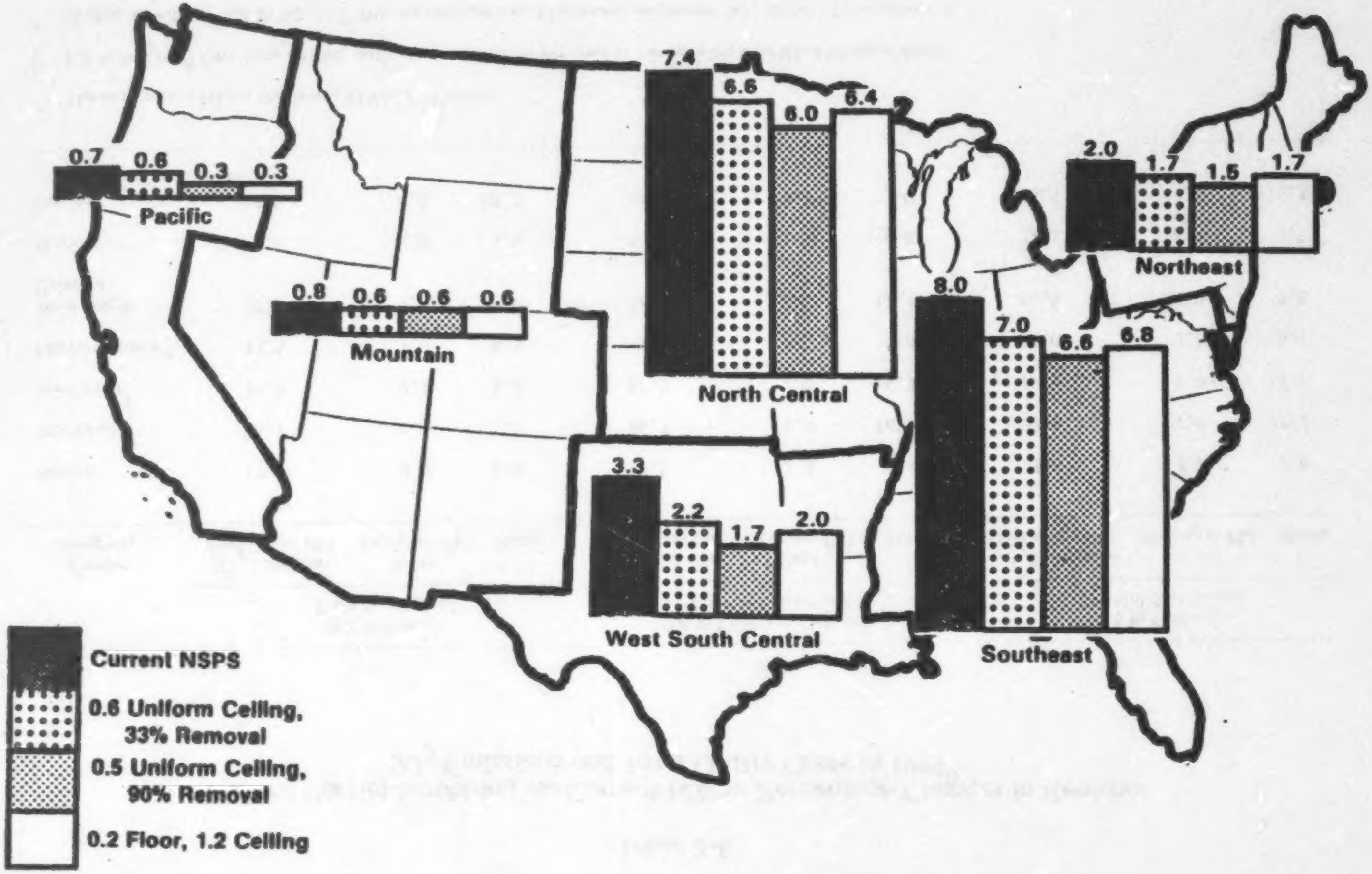
0.7
0.6
0.3
0.3
Pacific
0.8
0.6
0.6
0.6
Mountain
7.4
6.6
6.0
6.4
North Central
3.3
2.2
1.7
2.0
West South Central
8.0
7.0
6.6
6.8
Southeast
2.0
1.7
1.5
1.7
Northeast
Current NSPS
0.6 Uniform Ceiling, 33% Removal
0.5 Uniform Ceiling, 90% Removal
0.2 Floor, 1.2 Ceiling

Figure 3-3
National Percentage Increase in Total Utility Cost and Percentage Decrease in SO_2 Emissions for Revised NSPS, 1995
Lower FGD Costs

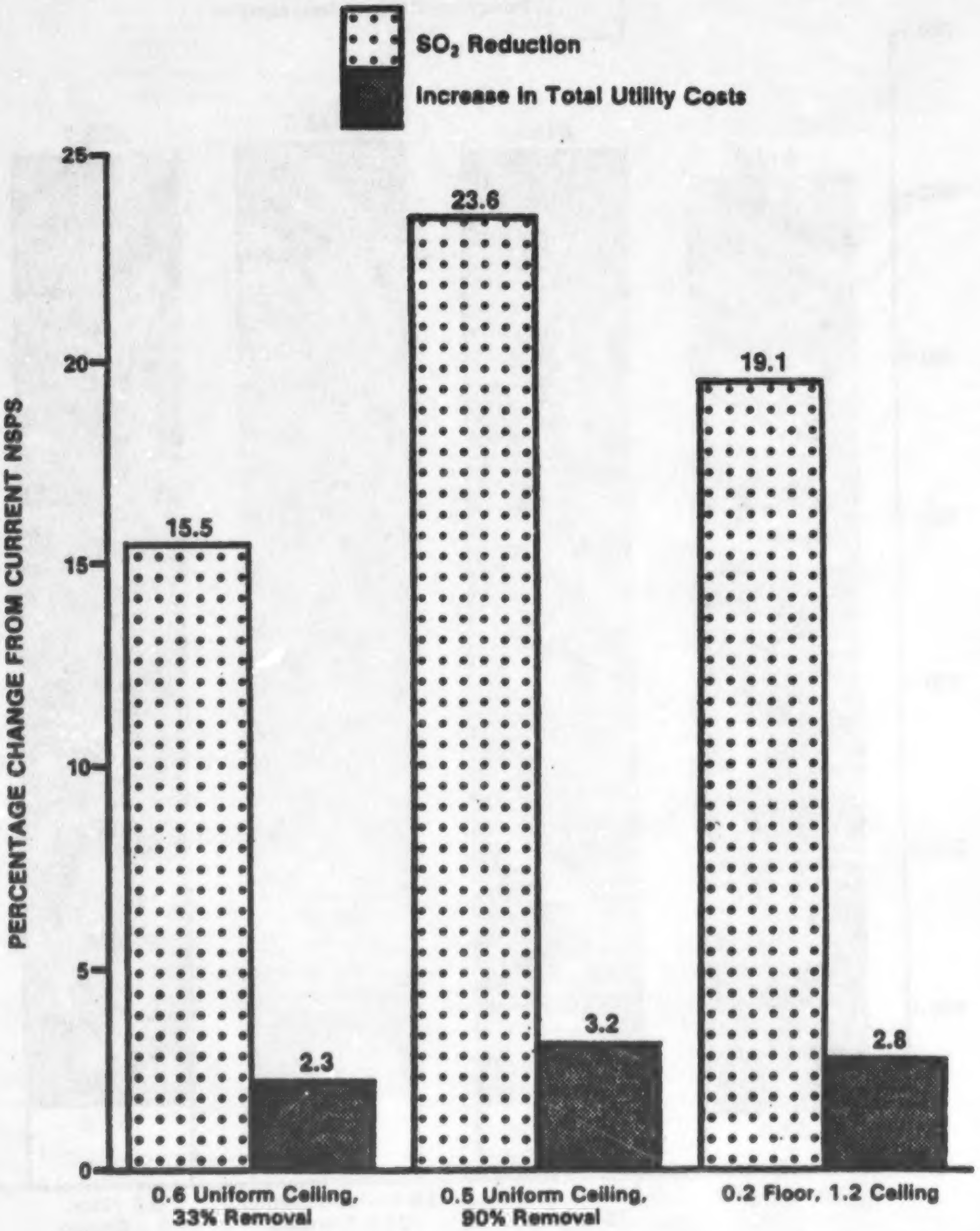

Figure 3-4
Comparison of National Pollution Control Investment
and Total Cumulative Investment, 1983-2000
(Billions 1975$)
Lower FGD Costs

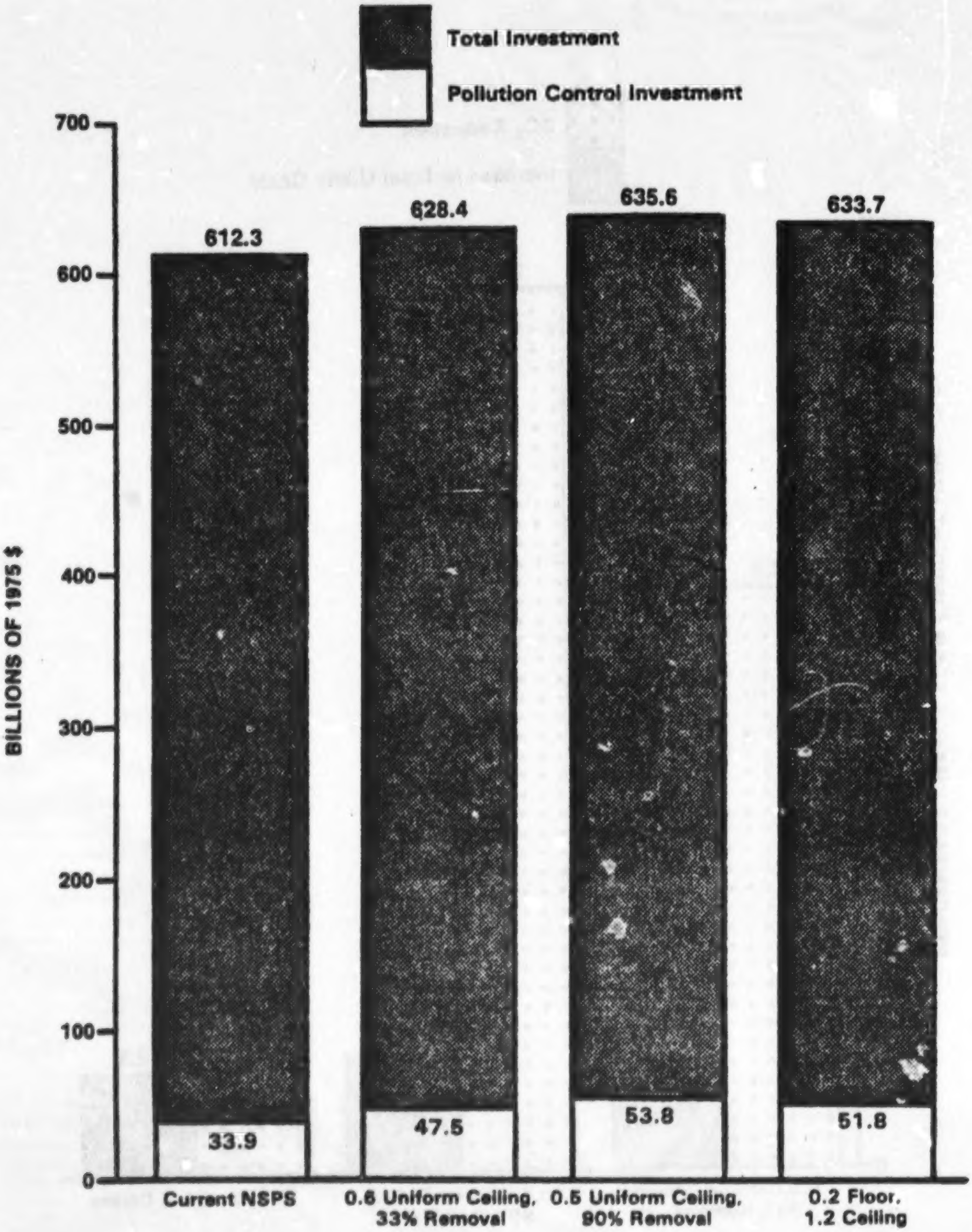

Table 3-5

Comparison of Cumulative Pollution Control Investment, FGD Capacity, and Total Coal Capacity

		Higher FGD Costs		
	Current NSPS Baseline	0.6 Uniform Ceiling	0.6 Floor	0.2 Floor
Pollution Control Investment (1983-2000)[a]	40.1	+27.4 (68%)[b]	+28.9 (72%)[b]	+41.7 (104%)[b]
FGD Capacity in 2000 (GW)[c]	194	423	459	510
Net Coal Capability[d] in 2000 (GW)	630	629	628	628

[a] Billions of 1975 dollars.

[b] Percentage change from baseline.

[c] Assumes wet scrubbing technologies only.

[d] Reflects penalties due to pollution control devices.

Table 3-6

Comparison of Cumulative Pollution Control Investment, FGD Capacity, and Total Coal Capacity

	Current NSPS Baseline	Lower FGD Costs		
		0.6 Uniform Ceiling	0.2 Floor	0.5 Ceiling 90% Removal
Pollution Control Investment (1983-2000)[a]	33.9	+13.6 (40)[b]	+17.9 (53)[b]	+19.9 (59)[b]
FGD Capacity in 2000 (GW)[c]	295.0	452	505	530
Net Coal Capability[d] in 2000 (GW)	632	631	632	631

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[a] Billions of 1975 dollars.

[b] Percentage change from baseline.

[c] Assumes wet scrubbing technologies only.

[d] Reflects penalties due to pollution control devices.

e. HOW DO THE ALTERNATIVE RNSPS DIFFER IN THEIR IMPACTS ON PRIMARY RESOURCE CONSUMPTION AND SOLID WASTE GENERATION?

For resource consumption, the major impacts presented here are utility fossil-fuel consumption (both for electricity generation and in-plant use), consumption of fuel for transporting coal, and water consumption for cooling and FGD use. The major solid wastes produced by coal-fired power plants are coal ash and FGD scrubber sludge.

The impacts of primary resource consumption and solid waste generation are felt locally, and we have calculated these impacts for each power plant, located by county. Here, however, we present only national impacts for the year 1995.

- Fossil fuel consumption. In 1995, total utility fossil-fuel consumption increases with more stringent standards. For example, total consumption increases from 27.8 quads under the current NSPS to 28.4 quads under a full scrubbing option with a 0.2 lb floor. The increase is due principally to increased coal requirements (24.3 to 25.1 quads) for scrubber operations. Utility oil consumption in 1995 will be about 3.1 quads and does not change appreciably in a specific year as a result of changes in RNSPS. Because oil is always more expensive than coal, the dispatching of oil plants does not change significantly across RNSPS. Changes in oil consumption over time arise principally from retirements of oil plants. These retirements are projected in the USM. Oil capacity over time is illustrated in Appendix H, and oil consumption is indicated in Appendix F.

  Existing oil plants are accounted for in the utility rate base, and fuel cost increases are often passed directly through to consumers. So long as oil is available in 1995, we believe that utilities will maintain any remaining oil plants rather than license and site additional coal capacity and seek rate increases from public utility commissions. Further, these existing oil plants may be located in urban areas where coal storage is not feasible; and they may be strategically located in the transmission grid so that early replacement is not desirable.

  Because of the costs of oil, these plants will be used for cycling rather than baseload generation. In the 1990s, reserve margins will average about 20 percent rather than keep to today's level, which can exceed 30 percent. This will further discourage the early retirement of reliable oil plants. (It should be noted that utility oil capacity and consumption are forecast in the USM to decrease substantially after 1986. The issue in question here is whether or not different RNSPS alone will induce significant changes in the oil retirement rate.)

Another factor should also be considered. If the future reliability of FGD scrubbers proves to be lower than anticipated and if this substantially reduces the availability of coal plants, it is possible that oil plants might be retired less rapidly under more stringent RNSPS. However, by 1995 under such a circumstance, utilities would probably build a slightly greater number of nuclear plants rather than retire oil plants differentially in response to more stringent RNSPS. In addition, experience should enhance future scrubber reliability. If the RNSPS induced the adoption of more nuclear capacity, oil consumption (as well as SO_2 emissions) could decrease.

All these factors militate against retiring oil steam plants simply on the basis of future oil prices. Plant-retirement criteria in the Utility Simulation Model are based on announced retirements, government policies mandating retirements (e.g., gas steam), and generating-unit age based on individual generating-unit data and the historical and announced ages of retired plants through 1987. Since economic criteria alone do not govern capacity expansion, significant changes in oil consumption are not projected in response to the cost increases imposed by RNSPS. It should be noted that all gas steam capacity is expected to be retired by 1992, and its retirement rate can affect regional coal capacity, emissions, and costs.

Diesel fuel consumed in 1995 in transporting coal by rail varies by scenario from 0.23 quads to 0.35 quads. It is highest under the current NSPS and under the 0.6 lb floor, where more western coal is shipped east. Fossil fuel consumption was illustrated earlier in Figure 2-12.

- Utility water consumption. Utility water consumption for cooling water increases across RNSPS in 1995 from about 4.9×10^6 acre-feet in the current NSPS case to 5.1×10^6 acre-feet in the 0.2 lb floor case. In comparison, FGD water consumption varies directly with FGD use, from about 0.22×10^6 acre-feet in the current NSPS case to 0.48×10^6 acre-feet under the full scrubbing option. Note that an increase of 1.1 percent per year in electricity demand between 1976 and 1995 increases cooling water consumption to about 6.1×10^6 acre-feet by 1995. This change in overall water consumption due to a different rate of growth in electricity demand exceeds any change expected from FGD usage. FGD water consumption impacts, however, will depend significantly on powerplant location. Utility water consumption is shown in Figure 2-13. These calculations do not assume the use of dry scrubbing technologies, which should lead to lower projected water consumption levels.

- Solid waste production. Utility scrubber sludge production in 1995 varies from 15×10^6 tons of sludge (dry basis) under the current NSPS to 51×10^6 tons of sludge under full scrubbing. (These projections are based on the higher FGD cost estimates. Under the lower FGD cost estimates, the amounts of sludge vary from 39.5×10^6 tons under the current NSPS to 57.7×10^6 tons under a 0.2 lb floor.) Total coal ash for disposal is projected to be 88×10^6 tons under the current NSPS and 100×10^6 tons under the 0.2 lb floor. Thus, the volumes of sludge produced are of the same order of magnitude as the volumes of coal ash. The costs of sludge disposal are accounted for in our FGD cost models. Whether or not disposal problems are encountered will depend on the specific location of the power plant. Utility production of solid wastes is illustrated in Figure 2-5.

f. HOW ARE UTILITY COAL PRODUCTION AND CONSUMPTION INFLUENCED BY THE SO_2 STANDARD AND BY DIFFERENT ESTIMATES OF FGD COSTS?

An alternative revised NSPS for SO_2, when set on a national basis, can affect regional utility coal production and consumption patterns significantly. It can also affect total required national coal production, primarily because of the differences in heating values of coals across regions. Assuming the higher cost estimates for scrubbers, Tables E-1 through E-3 (Appendix E) and Figure 2-14 show regional utility coal production in 1985, 1990, and 1995 under different SO_2 standards: the current NSPS, a 0.6 lb $SO_2/10^6$ Btu floor, a 0.2 lb $SO_2/10^6$ Btu floor, and a 0.6 lb $SO_2/10^6$ Btu ceiling. A summary of regional growth rates appears in Table E-4. Likewise, for the lower scrubber cost estimates, regional utility coal production for the different SO_2 standards is shown in Tables E-5 through E-7 and in Figure 2-15. A summary of nominal regional growth rates using the lower scrubber costs appears in Table E-8.

- Current NSPS. Using the higher scrubber cost estimates, projected utility coal production under the current NSPS increases from approximately 740 million tons in 1985 to 1,250 million tons in 1995. This is an increase of 510 million tons over ten years. Coal production in the Northern Great Plains is projected to increase by the greatest amount, from 210 million tons in 1985 to approximately 520 million tons in 1995. For the same ten-year period under the current NSPS, Gulf Coast lignite production is projected not to change substantially, while midwestern coal mining for utilities is projected to remain relatively constant, decreasing slightly over time.

  The lower scrubber cost estimates measurably enhance the competitive position of local coal. The rate of increase of western coal shipments east of the Mississippi drops from 7.7 percent per year to 2.2 percent per year when scrubber costs are lowered to the TVA estimates. (See Tables E-4 through E-8 in Appendix E). Likewise, the rate of increase of Gulf Coast coal use increases sharply, while shipments of coal from the Northern Great Plains area (Powder River Basin) do not increase.

- 0.6 lb floor (1.2 lb ceiling, 85 percent removal). Under the higher scrubber cost estimates, for a national 24-hour SO_2 standard with a 0.6 lb $SO_2/10^6$ Btu floor, projected utility coal production increases from 740 million tons in 1985 to 1,270 million tons in 1995. This is an increase of 530 million tons over ten years. Coal production in the Northern Great Plains is projected to increase by the greatest amount, from 210 to 480 million tons per year (45 million tons less than under the current NSPS). Appalachian coal production for utilities increases more than under the current NSPS, to 460 million tons in 1995. This reflects the increased use of local coal. This effect is also evident for Gulf Coast lignite and coal from other areas – primarily at the expense of growth in Northern Great Plains coal production. Lower FGD costs were not applied to an examination of this standard.

- 0.2 lb floor – the full scrubbing option. Under the higher scrubber cost estimates, for a national 24-hour floor of 0.2 lb $SO_2/10^6$ Btu (1.2 lb ceiling, 85 percent 24-hour SO_2 removal), projected utility coal production increases from 740 million tons in 1985 to 1,310 million tons in 1995. The use of local coals – coals from Appalachia, the Gulf Coast, and other areas – increases significantly as compared with local coal use under the current NSPS. Appalachian utility coal production is projected to increase by 200 million tons. Gulf Coast lignite mining increases substantially, and much of this growth is projected to occur between 1985 and 1990 as natural gas is phased out as a boiler fuel.

Lower scrubber cost estimates greatly enhance the position of local coals under the full scrubbing option. Production of midwestern coal for electric utilities increases between 1985 and 1995, whereas under other scenarios it remains level or decreases over time. Also, western coal shipments east of the Mississippi may decline, whereas they increase for other scenarios.

- 0.6 lb uniform annual ceiling. For both the lower and higher sets of FGD cost estimates, this represents a "middle" scenario between the current NSPS and a full scrubbing option. Compared with the latter two standards, assuming either the higher or lower FGD costs, the 0.6 lb ceiling enhances the position of local coal by allowing partial scrubbing of intermediate-sulfur coals.

- Utility movements of western coal. Western coal shipped to utilities east of the Mississippi River will be significantly affected by the level of the national SO_2 standard and scrubber costs, as shown in Figures 2-16 and 2-17.

Under the higher scrubber cost estimates and the current NSPS, shipments of low-sulfur western coal to utilities east of the Mississippi (predominantly to the Midwest) increase from 110 million tons in 1985 to 240 million tons in 1995. A similar growth pattern is observed for a 0.6 lb SO_2 floor. However, for a 0.2 lb floor and for the 0.6 lb uniform ceiling, the eastern markets for western coals do not grow substantially: shipments of western coal reach only 80 million tons in 1990 and 93 million tons in 1995 under the full scrubbing option; and under the 0.6 lb uniform ceiling they reach only 136 million tons in 1995.

These patterns change markedly when the lower scrubber cost estimates are used. Under the current NSPS, assuming the lower estimates, eastern utility consumption of low-sulfur western coal grows by only 2.2 percent per year (compared with a growth of 7.7 percent per year using the higher scrubber cost estimates). Under a 0.6 lb uniform annual ceiling, the rate of increase is only 1.3 percent per year; while under full scrubbing the eastern market for western coal may even decline.

The foregoing results are summarized as follows:

- Total national utility coal production is projected to increase as a result of the tightening of SO_2 emission standards. Under the current NSPS, national utility coal consumption is projected to grow at an average annual rate of 5.3 percent between 1985 and 1995. This growth rate is projected to increase to 5.4 percent under a 0.6 lb standard, and to 5.8 percent under a 0.2 lb standard.

- The use of low-sulfur coal in power plants east of the Mississippi is greatest under the current NSPS. It decreases under a 0.6 lb uniform ceiling option and further under a full scrubbing option.

- If lower scrubber costs are used, the position of local coal is greatly enhanced while long-distance shipments are curtailed. The largest differences between the higher and lower FGD cost estimates appear in the projections for the use of low-sulfur coal east of the Mississippi:

    - Under the current NSPS, western coal shipments eastward increase by 7.7 percent per year using the higher FGD cost estimates but only by 2.2 percent per year using the lower FGD costs.

    - Under the full scrubbing standard, western coal shipments eastward increase by 1.6 percent per year using the higher FGD cost estimates but may even decline using the lower costs.

- Coal production in all regions of the U.S. will be greater under all RNSPS than 1978 regional production levels.

II. WHAT ARE THE DIFFERENCES BETWEEN THE PROJECTED IMPACTS OF THE FULL AND PARTIAL SCRUBBING ALTERNATIVES?

a. WHAT ARE THE COST AND EMISSION DIFFERENCES BETWEEN THE VARIOUS FULL AND PARTIAL SCRUBBING OPTIONS?

Using the higher (PEDCo) scrubber cost estimates, neither this nor other studies show significant cost or emission differences between the full and partial scrubbing options based on a 24-hour averaging time (0.2 lb floor and 0.6 lb floor). Differences do occur for the 0.6 lb uniform ceiling option (which is an annual form of the RNSPS), as noted above.

Why are the differences between the 0.2 lb floor and 0.6 lb floor options not larger? One major reason is that the RNSPS principally affect coal-fired capacity. While coal-fired capacity accounts for a major fraction of the total projected national generating capacity and steadily increases over time, noncoal capacity still represents approximately one-half of the total projected capacity and slightly less than one-half of the electricity projected to be generated by the year 2000. (See Appendix H.) Thus, even if the costs of generating electricity from RNSPS coal plants were to increase very rapidly, the overall cost difference across scenarios would be moderated by the costs associated with noncoal plants.

However, there are several reasons why the differences between the 0.2 lb floor and 0.6 lb floor standards are not larger within the coal-fired plant category itself. The calculated differences in cost between alternative RNSPS are determined primarily by three elements: the design, cost, and operating characteristics of FGD scrubbers; the form of the revised standard; and the coal burned. A number of assumptions, including the relative standard deviation (RSD) assumed for coal sulfur variability (24-hour RSD = 0.15 for uncleaned coals), have served to reduce the observed cost and emission differentials between these two very similar 24-hour SO_2 standards. In practice, if different assumptions proved true, the actual differentials could be greater.

Several key factors embedded in the analyses have influenced the estimated pollution control costs and reduced the cost differentials between these two options.

- Compliance calculations and scrubber sizes are based on the "worst case" situation. That is, the assumed design of the FGD scrubber system is such that compliance is maintained on days when the 24-hour average coal sulfur content is 1.3 times the long-term average coal sulfur content (and at least 1.45 times the long-term average content in the "no exemptions" cases).
- In cases where the SO_2 emission floor controls (that is, where the percentage SO_2 removal can be less than the prescribed 85 percent daily removal), it has been assumed

that the SO_2 emission level will never exceed the floor. Thus, the average coal sulfur content must produce emissions below the floor by an amount determined by the coal sulfur RSD. If the assumed RSDs were smaller than 0.15, as they probably are for cleaned coals and for larger lot sizes, emission levels under 24-hour or 30-day partial scrubbing options would be higher.

- FGD systems are assumed to be designed with "fixed bypass," that is, with a constant SO_2 removal efficiency achieved through bypassing a fixed percentage of the flue gas stream around the scrubber. In general, bypassing a portion of the flue gas results in capital cost savings, because smaller FGD systems are required. Operating costs are lower because less SO_2 is removed. The fixed bypass conditions are determined by the required emission level, the coal to be burned, and the emission standard.

  For days when incoming coal sulfur is below the long-term average level, resulting in 24-hour emissions below the emissions floor (which is never to be exceeded), no allowance was made for variable bypass (which would increase emissions up to the floor). Had variable bypass been assumed, the emission levels projected for plants subject to the floor would have been higher by a factor of about 1.5. As Figure 2-18 shows, variable bypass is not cost effective, since emissions increase more rapidly than cost savings, especially for low-sulfur coals. If variable bypass were allowed, utilities would emit at the level of the specified standard, not below it. (In this study's analysis of annual standards where an annual average ceiling controls, annual emissions are at the level of the ceiling; that is, the annual RSD is zero.)

b. HOW DOES THE FORM OF THE REVISED STANDARD INFLUENCE THE COSTS OF POLLUTION CONTROLS?

The form and technical requirements of any given standard have numerous implications for pollution control costs. Many of these implications are presented in detail in a set of graphs that appears in Appendix C. The sensitivity studies discussed in the following sections address this question for various coals. The general conclusions are as follows:

- For the same annual emission level, an annual average standard compared with a 24-hour standard permits greater FGD gas bypass for a given coal and results in lower energy penalties. As noted above, all standards were evaluated assuming a constant SO_2 removal efficiency, i.e., fixed bypass. (The possibility of a utility emitting at low levels and then completely bypassing the FGD system for the rest of the year to meet an annual average emission limit was precluded by the fixed-bypass assumption.) Nevertheless, short-term emissions resulting from coal sulfur variability may be higher than the annual average. This likelihood and the diurnal nature of adverse air pollution episodes indicate the need for setting appropriate 24-hour standards in conjunction with any longer-term standards.

- To achieve the same annual emission level for a given coal, an annual average or 30-day SO_2 standard compared with the equivalent 24-hour average standard will permit lower costs per kilowatt-hour of electricity produced.
- As indicated earlier, variable bypass on FGD scrubbers is less cost effective than fixed bypass for emission control. (See Figure 2-18.)
- For the 24-hour standards, given the specified assumptions regarding scrubber design and performance, there is very little difference in annual emissions between the "without exemptions" and "with exemptions" cases (the latter being those cases in which the mandatory 85 percent removal is allowed to drop to 75 percent three days per month). Since the three-day-per-month exemption should permit greater flexibility in utility operations, it appears to be an effective element of a 24-hour standard.

III. HOW WILL UTILITY COAL CHOICES IN KEY STATES BE AFFECTED BY DIFFERENT SO_2 EMISSION STANDARDS AND UNCERTAINTIES IN KEY FACTORS?

a. WHAT ESTIMATES CAN BE MADE REGARDING THE TYPICAL UTILITY COSTS OF BUYING, TRANSPORTING, AND BURNING DIFFERENT COALS, AND OF REQUIRED POLLUTION CONTROLS, AS A FUNCTION OF THE SO_2 STANDARD?

For a series of 24-hour and annual average SO_2 standards of between 0.2 and 1.2 lb $SO_2/10^6$ Btu, the levelized fuel-cycle cost has been calculated for 500 MW coal-fired power plants coming on line after 1982 (see Appendixes B and C). For each state, a power-plant location has been selected near a key city for which a change in SO_2 standard may critically influence the chosen source of coal supply and therefore the resulting emissions. Swing states – those most sensitive to changes in fuel and pollution control costs and therefore subjected to the in-depth analyses reported herein – include Ohio, Indiana, Florida, and Texas. Results for Ohio are discussed in the text; results for the other states are included in Appendix C. These analyses show that:

- For power plants located in eastern and midwestern states, reducing the level of the 24-hour SO_2 floor increases the fuel-cycle cost of western coals compared with that of eastern (local) coals. Generally for most states, at some level of floor or ceiling below 1.2 lb $SO_2/10^6$ Btu, an eastern (local) coal becomes the most economical choice on the basis of levelized cost per 10^6 Btu of coal burned; this measure of cost is proportional to the cost per kilowatt-hour of electricity generated. (See Appendix B.) In this study, estimates were made of "crossover points," that is, of SO_2 floors above which partially scrubbed western coals will be cheaper to use than higher-sulfur eastern coals, which require a greater degree of scrubbing. For standards in the "crossover" range, the responses of utilities in each state are subject to greater uncertainty.

- Levelized fuel-cycle costs per kilowatt-hour for typical (low-sulfur) western coals may increase by as much as 24 percent over the range of 24-hour SO_2 floors and over the range of annual ceilings of between 1.2 and 0.2 lb $SO_2/10^6$ Btu. However, for typical (higher-sulfur) eastern coals, fuel-cycle costs either remain constant (since nearly "full scrubbing" will be required for all floors or ceilings) or increase by not more than approximately 10 percent over the range of standards analyzed. Figure 3-5 illustrates the levelized cost per million Btu of scrubbing various coals. Figures 3-6 and 3-7 illustrate estimated variations in fuel-cycle costs for power plants near Columbus, Ohio; additional figures for other key states are presented in Appendix C. The coals illustrated in Figures 3-6 and 3-7 were selected from a list of over 30 candidate coals on the basis of their comparatively low fuel-cycle costs near Columbus, Ohio.

- Emissions from coal-fired power plants will not exceed a specified 24-hour SO_2 floor (if the floor controls) and may be less than the floor depending on additional specifications. The additional specifications include coal sulfur RSD (relative standard deviation – see Glossary). The

Figure 3-5
Comparison of FGD Cost Effectiveness per Btu of Fuel Input under Annual Average SO_2 Control Alternatives

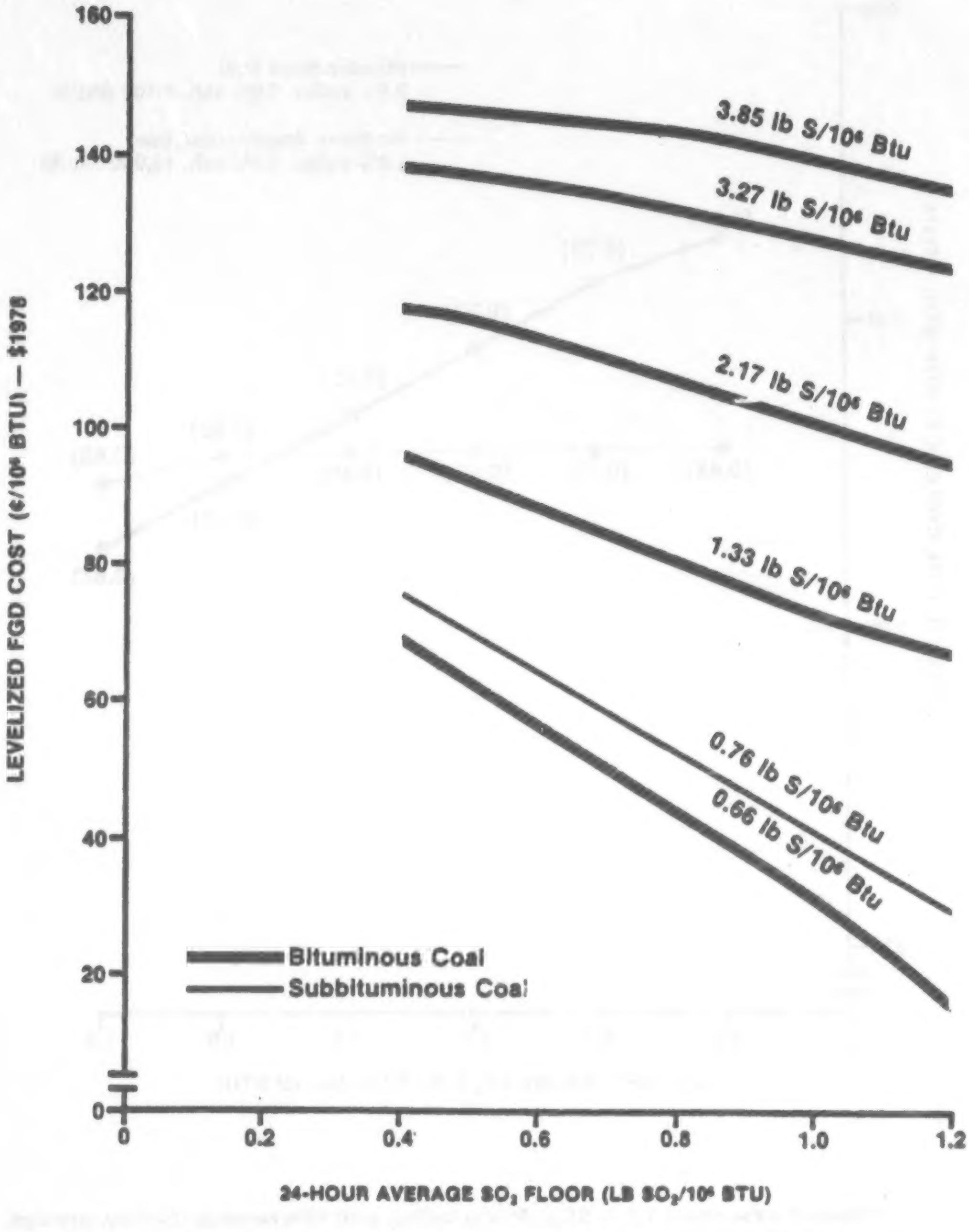
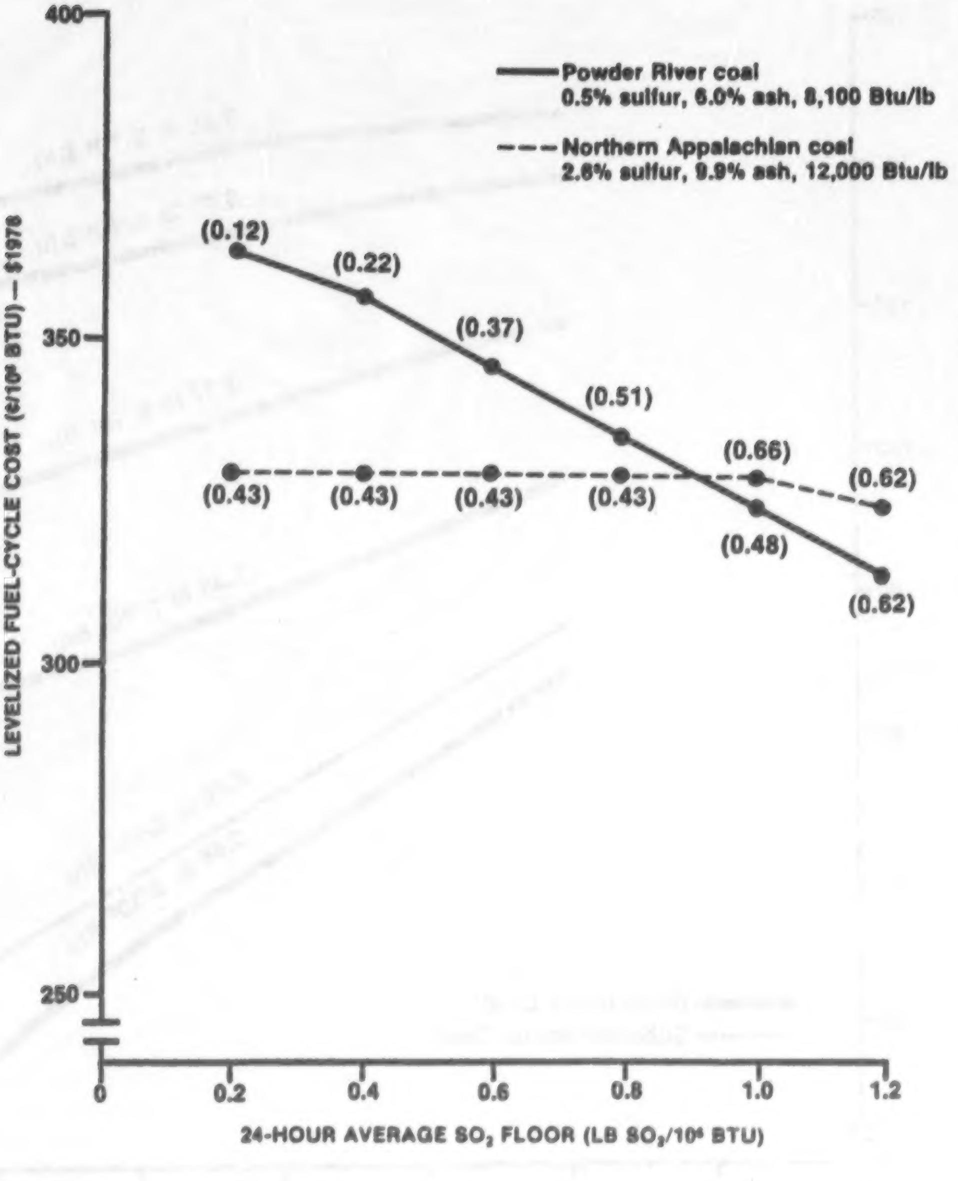
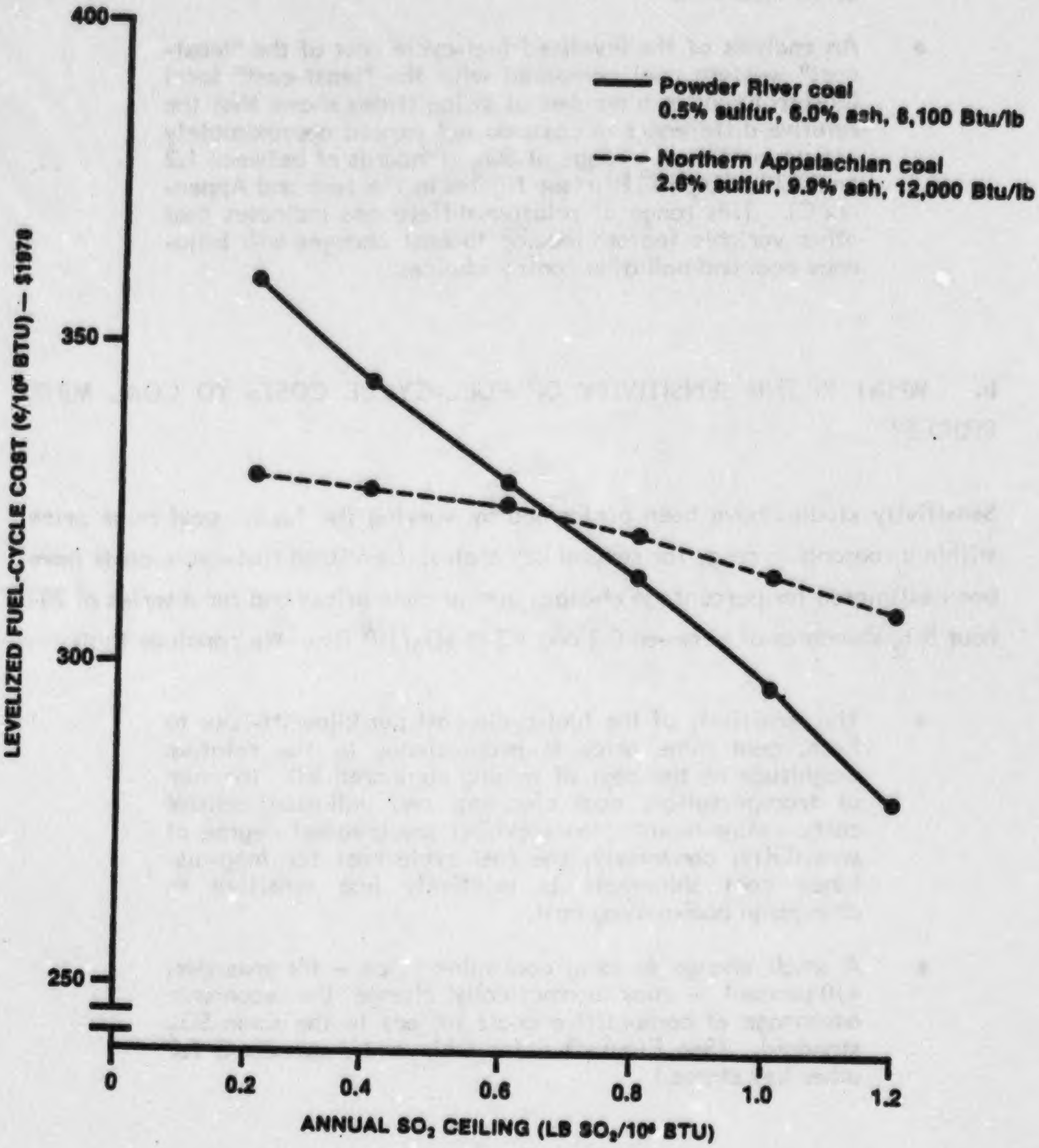


Figure 3-6
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor
(Columbus, Ohio)



Note: Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month). ( ) = annual emissions (lb $SO_2/10^6$ Btu).

Figure 3-7
Sensitivity of Levelized Fuel-Cycle Cost to Annual SO_2 Ceiling
(Columbus, Ohio)



Note: **Calculations assume no mandatory percentage removal requirement.**

higher the assumed RSD, the lower the average emissions will be in order never to exceed the floor.

- Emissions from coal-fired power plants subject to an annual SO_2 ceiling with no mandatory percentage removal are identical for all coals. (For annual standards, the coal sulfur RSD = 0.)

- An analysis of the levelized fuel-cycle cost of the "least-cost" western coal compared with the "least-cost" local (eastern) coal in a number of swing states shows that the relative differences in costs do not exceed approximately ±15 percent over a range of SO_2 standards of between 1.2 and 0.2 lb $SO_2/10^6$ Btu (see figures in the text and Appendix C). This range of relative differences indicates that other variable factors leading to cost changes will influence coal and pollution control choices.

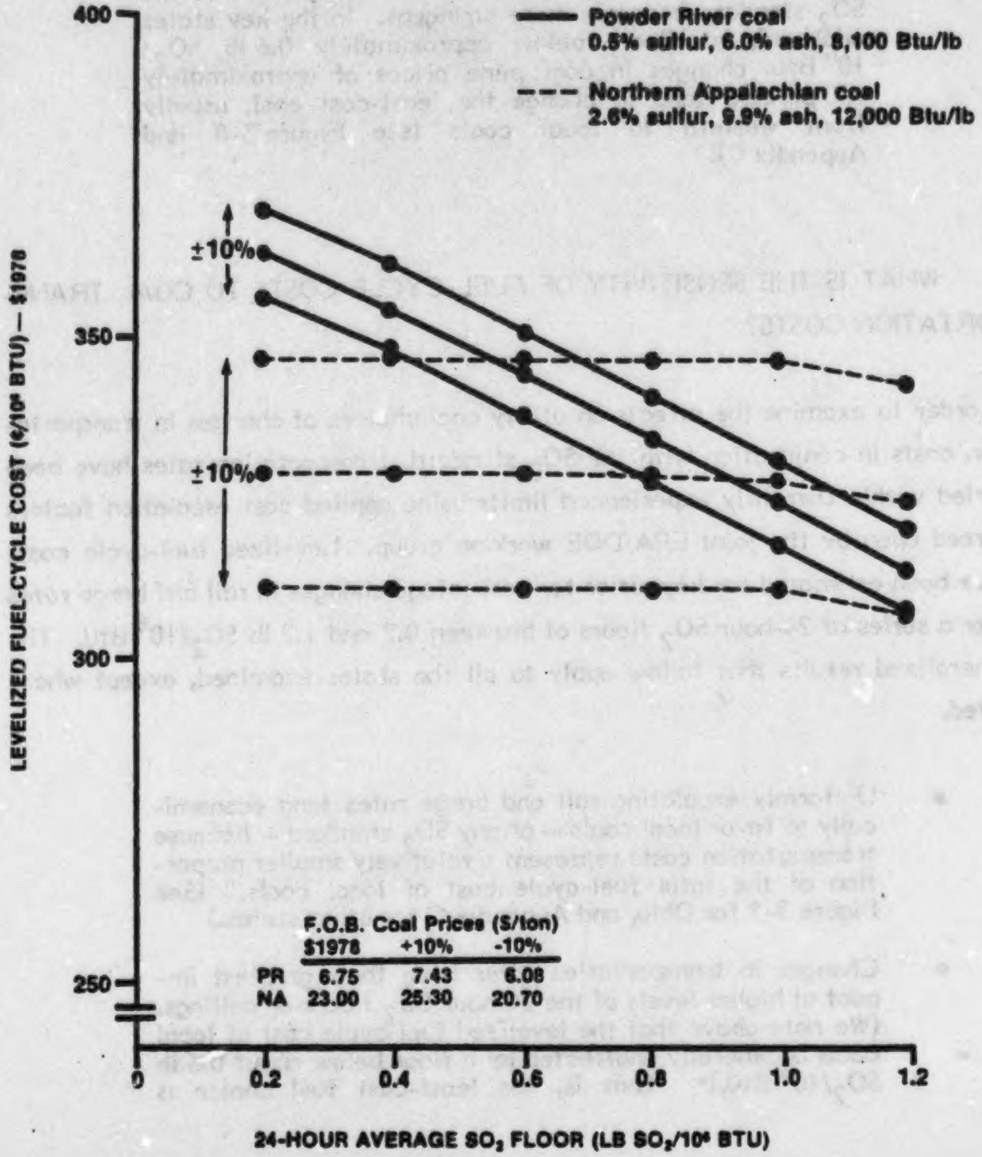
b. WHAT IS THE SENSITIVITY OF FUEL-CYCLE COSTS TO COAL MINE PRICES?

Sensitivity studies have been performed by varying the f.o.b. coal mine price within a reasonable range for several key states. Levelized fuel-cycle costs have been estimated for percentage changes in coal mine prices and for a series of 24-hour SO_2 standards of between 0.2 and 1.2 lb $SO_2/10^6$ Btu. We conclude that:

- The sensitivity of the fuel-cycle cost per kilowatt-hour to f.o.b. coal mine price is proportional to the relative magnitude of the cost of mining compared with the sum of transportation, coal cleaning, and pollution control costs. Mine-mouth plants exhibit the greatest degree of sensitivity; conversely, the fuel-cycle cost for long-distance coal shipments is relatively less sensitive to changes in coal-mining cost.

- A small change in local coal mine price — for example, ±10 percent — may dramatically change the economic advantage of competitive coals subject to the same SO_2 standard. (See Figure 3-8 for Ohio and Appendix C for other key states.)

Figure 3-8
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and F.O.B. Coal Mine Prices
(Columbus, Ohio)



F.O.B. Coal Prices ($/ton)

	$1978	+10%	-10%
PR	6.75	7.43	6.08
NA	23.00	25.30	20.70

Note: **Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month). Transportation rates: rail < 250 miles, 2.25¢/ton-mile; > 250 miles, 1.20¢/ton-mile; water 0.5¢/ton-mile.**

- Western coal becomes increasingly competitive as coal mine prices uniformly increase for any specified SO_2 standard. (Thus, inflationary trends in coal mining tend to favor the use of western coal in the Midwest.)

- Since local coals are favored at more stringent standards, and since increases in coal mine prices have a greater relative impact on fuel-cycle costs for local coals, overall costs become more sensitive to coal-mining costs as the SO_2 standard becomes more stringent. In the key states analyzed, at floors below approximately 0.6 lb $SO_2/10^6$ Btu, changes in coal mine prices of approximately ±10 percent tend to change the least-cost coal, usually from western to local coals (see Figure 3-8 and Appendix C).

c. WHAT IS THE SENSITIVITY OF FUEL-CYCLE COSTS TO COAL TRANSPORTATION COSTS?

In order to examine the effects on utility coal choices of changes in transportation costs in conjunction with the SO_2 standard, transportation rates have been varied within currently experienced limits using applied cost escalation factors agreed upon by the joint EPA/DOE working group. Levelized fuel-cycle costs have been estimated for key cities for percentage changes in rail and barge rates over a series of 24-hour SO_2 floors of between 0.2 and 1.2 lb $SO_2/10^6$ Btu. The generalized results that follow apply to all the states examined, except where noted.

- Uniformly escalating rail and barge rates tend economically to favor local coals – at any SO_2 standard – because transportation costs represent a relatively smaller proportion of the total fuel-cycle cost of local coals. (See Figure 3-9 for Ohio, and Appendix C for other states.)

- Changes in transportation rates have their greatest impact at higher levels of the 24-hour SO_2 floors or ceilings. (We note above that the levelized fuel-cycle cost of local coals is generally unaffected by a floor below about 0.6 lb $SO_2/10^6$ Btu.)* That is, the least-cost fuel choice is

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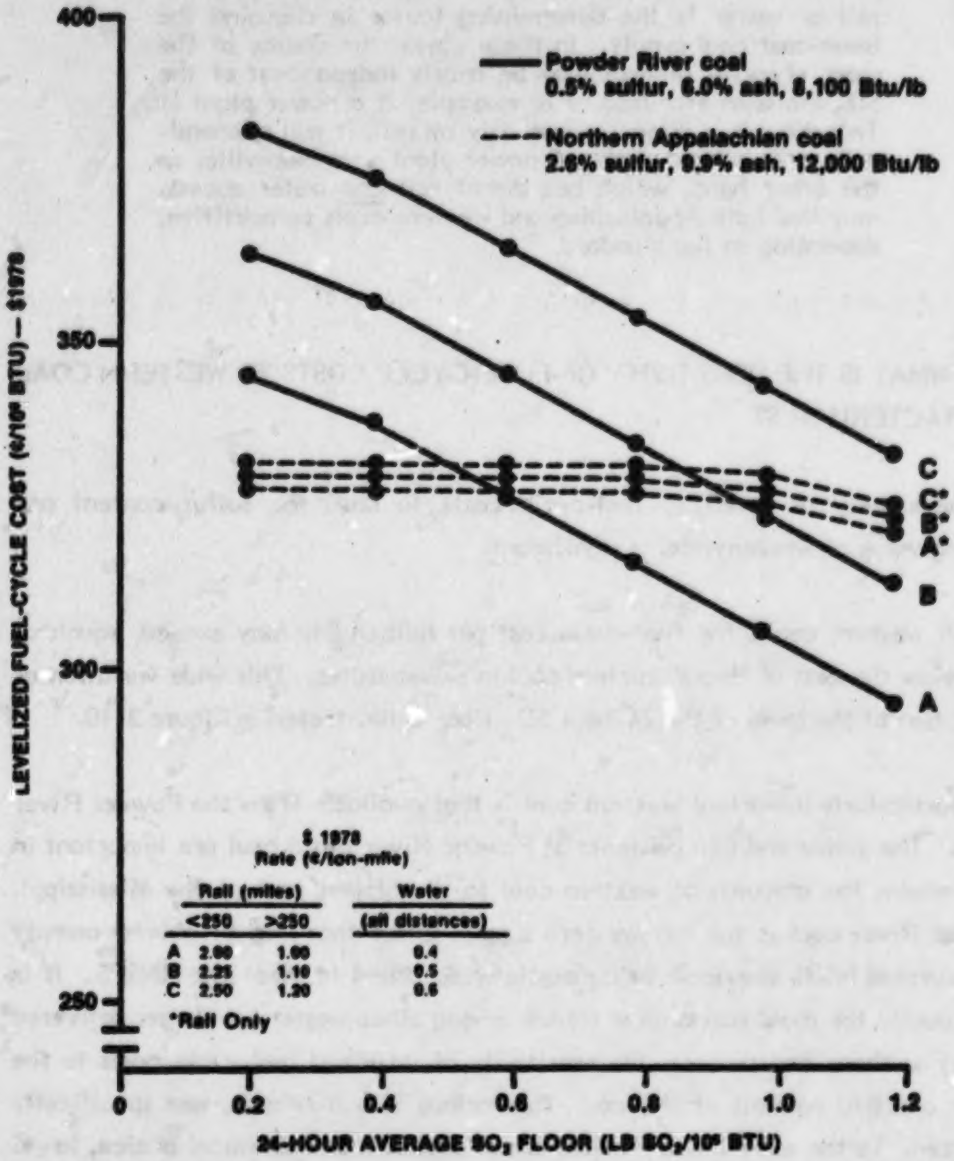
* For a 24-hour standard requiring a ceiling of 1.2 lb $SO_2/10^6$ Btu and 85 percent removal. The results are also unaffected by annual standards with a uniform ceiling below about 0.5 lb $SO_2/10^6$ Btu.

Figure 3-9

Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and Transportation Rate

(Columbus, Ohio)



Note: **Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month).**

relatively insensitive to the transportation rate at levels of the 24-hour SO_2 floor that require nearly full scrubbing.

- However, for several states, the location of the power plant in terms of accessibility to coal delivery by either rail or water is the determining factor in choosing the least-cost coal supply. In these cases, the choice of the most economical coal may be nearly independent of the SO_2 emission standard. For example, if a power plant in Tennessee has direct access only by rail, it will economically utilize local coals. A power plant near Nashville, on the other hand, which has direct rail and water access, may find both Appalachian and western coals competitive, depending on the standard.

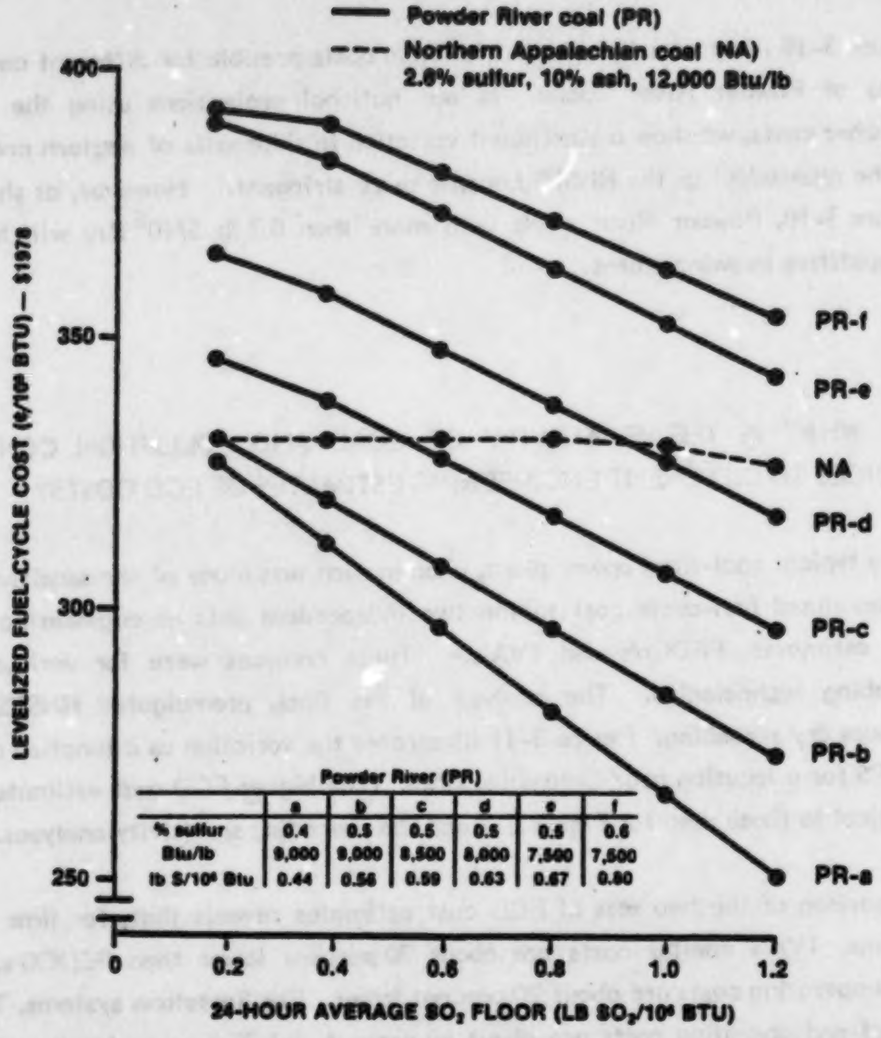
d. WHAT IS THE SENSITIVITY OF FUEL-CYCLE COSTS TO WESTERN COAL CHARACTERISTICS?

The sensitivity of levelized fuel-cycle costs to both the sulfur content and heating value of western coal is significant.

For all western coals, the fuel-cycle cost per million Btu may exceed, equal, or fall below the cost of "local" eastern coal in swing states. This wide variation as a function of the level of the 24-hour SO_2 floor is illustrated in Figure 3-10.

One particularly important western coal is that available from the Powder River Basin. The sulfur and Btu contents of Powder River Basin coal are important in determining the amounts of western coal to be shipped east of the Mississippi. Powder River coal is the key western supply source that may be able to comply with current NSPS standards or be partially scrubbed to meet the RNSPS. It is also usually the most economical choice among other western coals per delivered Btu. For these two reasons, the sensitivity of levelized fuel-cycle costs to the sulfur and Btu content of this coal, for various SO_2 standards, was specifically analyzed. To the extent that Powder River coal is the economical choice, lower emissions may result from its use.

Figure 3-10
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO$_2$ Floor and Powder River Coal Characteristics
(Columbus, Ohio)



Powder River (PR)

	a	b	c	d	e	f
% sulfur	0.4	0.5	0.5	0.5	0.5	0.6
Btu/lb	9,000	9,000	8,500	8,000	7,500	7,500
lb S/10^6 Btu	0.44	0.56	0.59	0.63	0.67	0.80

Note: Calculations assume a 1.2 lb SO$_2$/10^6 Btu ceiling with 85% removal (24-hour average with exemptions of three days per month). Powder River $1978/ton = 6.75; Northern Appalachian $1978/ton = 23.00.

In Columbus, Ohio, Powder River coals of lower sulfur and higher Btu content could be economically preferred over local coals for any level of 24-hour SO_2 floor. However, Powder River coals of below a certain Btu value or above a certain sulfur percentage could cost more than local coals for any level of 24-hour SO_2 floor. The most probable Powder River Basin coal to be mined between now and 1990 should be that with about 0.6 lb $S/10^6$ Btu. (See Appendix D.) In Ohio, this coal would be competitive with local coals.

Figure 3-10 illustrates the wide variation in costs possible for different compositions of Powder River coals. In our national projections using the higher scrubber costs, we show a significant variation in shipments of western coal east of the Mississippi as the RNSPS become more stringent. However, as shown in Figure 3-10, Powder River coals with more than 0.7 lb $S/10^6$ Btu will be less competitive in swing states.

e. WHAT IS THE SENSITIVITY OF COAL AND POLLUTION CONTROL CHOICES TO DIFFERENT ENGINEERING ESTIMATES OF FGD COSTS?

For a typical coal-fired power plant, examination was made of the sensitivity of the levelized fuel-cycle cost to the two independent sets of engineering FGD cost estimates, PEDCo's and TVA's.* These analyses were for various wet scrubbing technologies. The analysis of the final, promulgated RNSPS also includes dry scrubbing. Figure 3-11 illustrates the variation as a function of the RNSPS for a location near Columbus, Ohio. (The higher FGD cost estimates are identical to those used for Figure 3-7 and the preceding sensitivity analyses.)

Comparison of the two sets of FGD cost estimates reveals that, for lime FGD systems, TVA's capital costs are about 30 percent lower than PEDCO's, and TVA's operating costs are about 20 percent lower. For limestone systems, TVA's capital and operating costs are about 40 percent and 27 percent lower, respectively, than PEDCo's.

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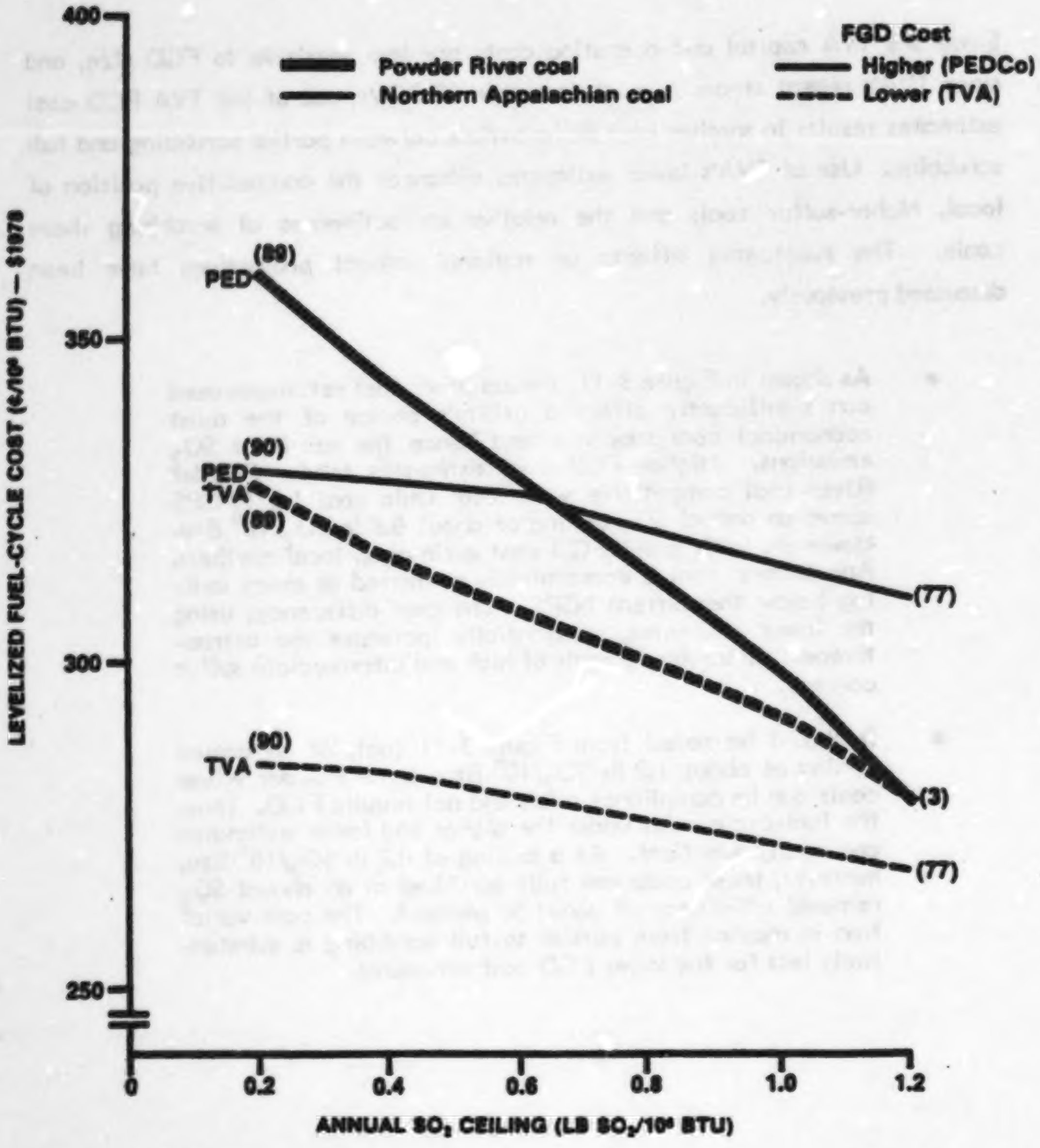
* Again, the engineering differences between the PEDCo and TVA estimates are discussed briefly in Appendix A.

Figure 3-11
Sensitivity of Levelized Fuel-Cycle Cost to FGD Cost
(Columbus, Ohio)



Note: ( ) = percentage SO_2 removal.

The TVA costs appear to be less sensitive than PEDCo's to scrubber size, to the gas flow measured in actual cubic feet per minute, and to SO_2 removed per hour. PEDCo's and TVA's estimates of FGD electricity consumption (and resulting capacity penalty) are about the same, while TVA's estimate of reheat steam is only about 20 percent of PEDCo's.

Since the TVA capital and operating costs are less sensitive to FGD size, and since TVA's reheat steam is much less than PEDCo's, use of the TVA FGD cost estimates results in smaller cost differentials between partial scrubbing and full scrubbing. Use of TVA's lower estimates enhances the competitive position of local, higher-sulfur coals and the relative attractiveness of scrubbing these coals. The substantial effects on national impact projections have been discussed previously.

- As shown in Figure 3-11, the scrubber cost estimates used can significantly affect a utility's choice of the most economical coal supply – and hence the resultant SO_2 emissions. Higher FGD cost estimates render Powder River coal competitive with local Ohio coal for RNSPS above an annual SO_2 ceiling of about 0.6 lb $SO_2/10^6$ Btu. However, with lower FGD cost estimates, local northern Appalachian coal is economically preferred at every ceiling below the current NSPS. The cost difference, using the lower estimates, substantially increases the attractiveness of scrubbing coals of high and intermediate sulfur content.

- It should be noted from Figure 3-11 that, at an annual ceiling of about 1.2 lb $SO_2/10^6$ Btu, some Powder River coals can be compliance coals and not require FGD. Thus, the fuel-cycle costs under the higher and lower estimates are nearly identical. At a ceiling of 0.2 lb $SO_2/10^6$ Btu, however, these coals are fully scrubbed at an annual SO_2 removal efficiency of about 90 percent. The cost variation in moving from partial to full scrubbing is substantially less for the lower FGD cost estimates.

As shown in the preceding discussion, this reduced cost variation under the lower FGD cost estimates would lead to dramatically lower consumption of western coals east of the Mississippi and to the increased utilization of local coals.

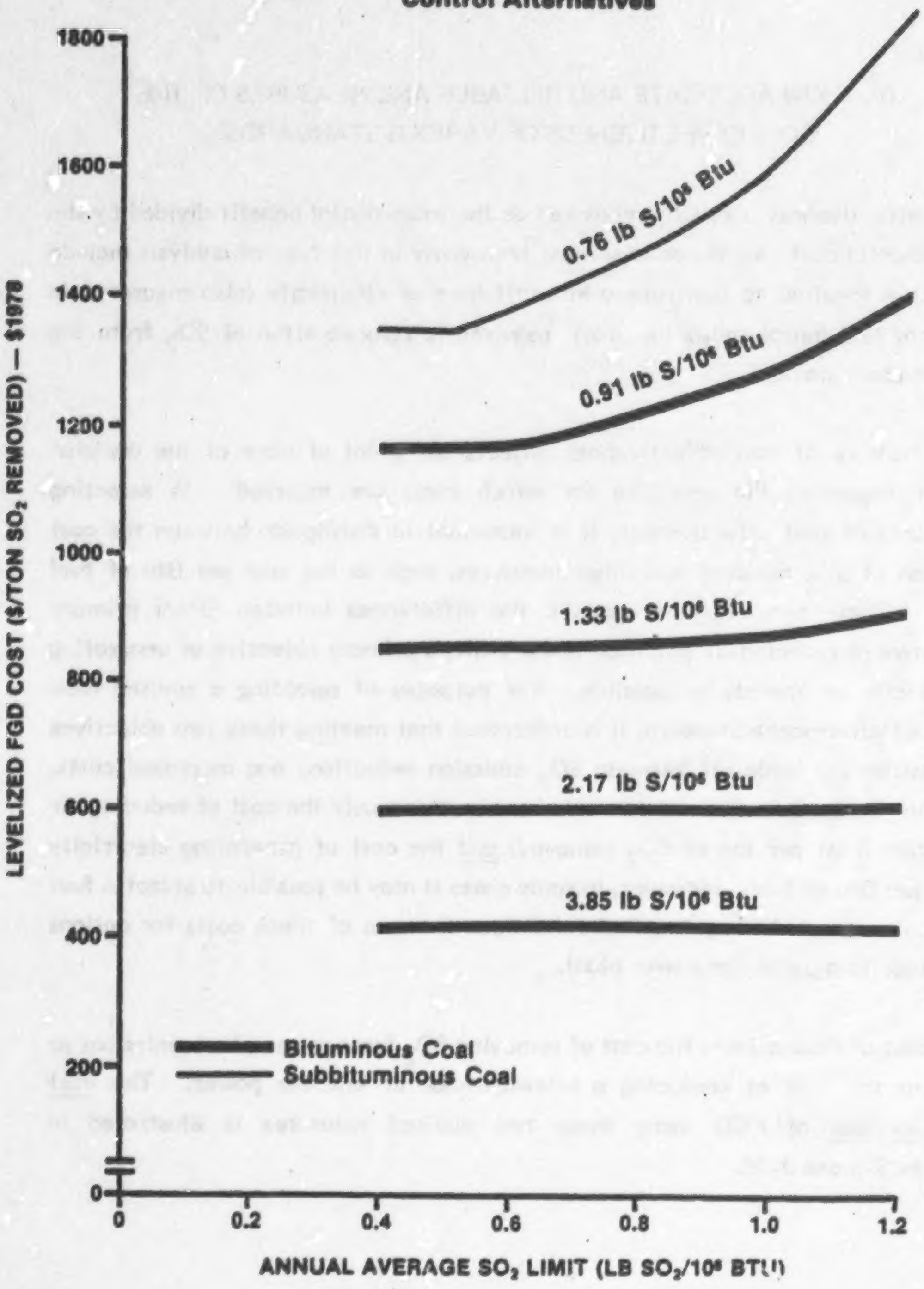
IV. HOW ACCURATE AND RELIABLE ARE MEASURES OF THE COST EFFECTIVENESS OF VARIOUS STANDARDS?

Cost effectiveness is usually measured as the incremental benefit divided by the incremental cost. Measures used most frequently in this type of analysis include the cost required to generate a kilowatt-hour of electricity (also measured in Btu's of fuel input) and/or the cost required to remove a ton of SO_2 from the power-plant stack.

Any measure of cost effectiveness reflects the point of view of the decision maker regarding the objective for which costs are incurred. In selecting measures of cost effectiveness, it is important to distinguish between the cost per ton of SO_2 removed and other measures, such as the cost per Btu of fuel used. These two measures capture the differences between EPA's primary objective of reducing air pollution and a utility's primary objective of generating electricity as cheaply as possible. For purposes of selecting a revised New Source Performance Standard, it is understood that meeting these two objectives necessitates a trade-off between SO_2 emission reductions and increased costs. In other words, it is difficult to minimize simultaneously the cost of reducing air pollution (cost per ton of SO_2 removed) and the cost of generating electricity (cost per Btu of fuel). However, in some cases it may be possible to select a fuel and pollution control option that minimizes the sum of these costs for options available to a particular power plant.

The cost of FGD affects the cost of removing SO_2 from power-plant emissions as well as the cost of producing a kilowatt-hour of electric power. The cost effectiveness of FGD using these two distinct measures is illustrated in Figures 3-5 and 3-12.

Figure 3-12
Comparison of FGD Cost Effectiveness per Ton of SO_2 Removed under Annual Average SO_2 Control Alternatives



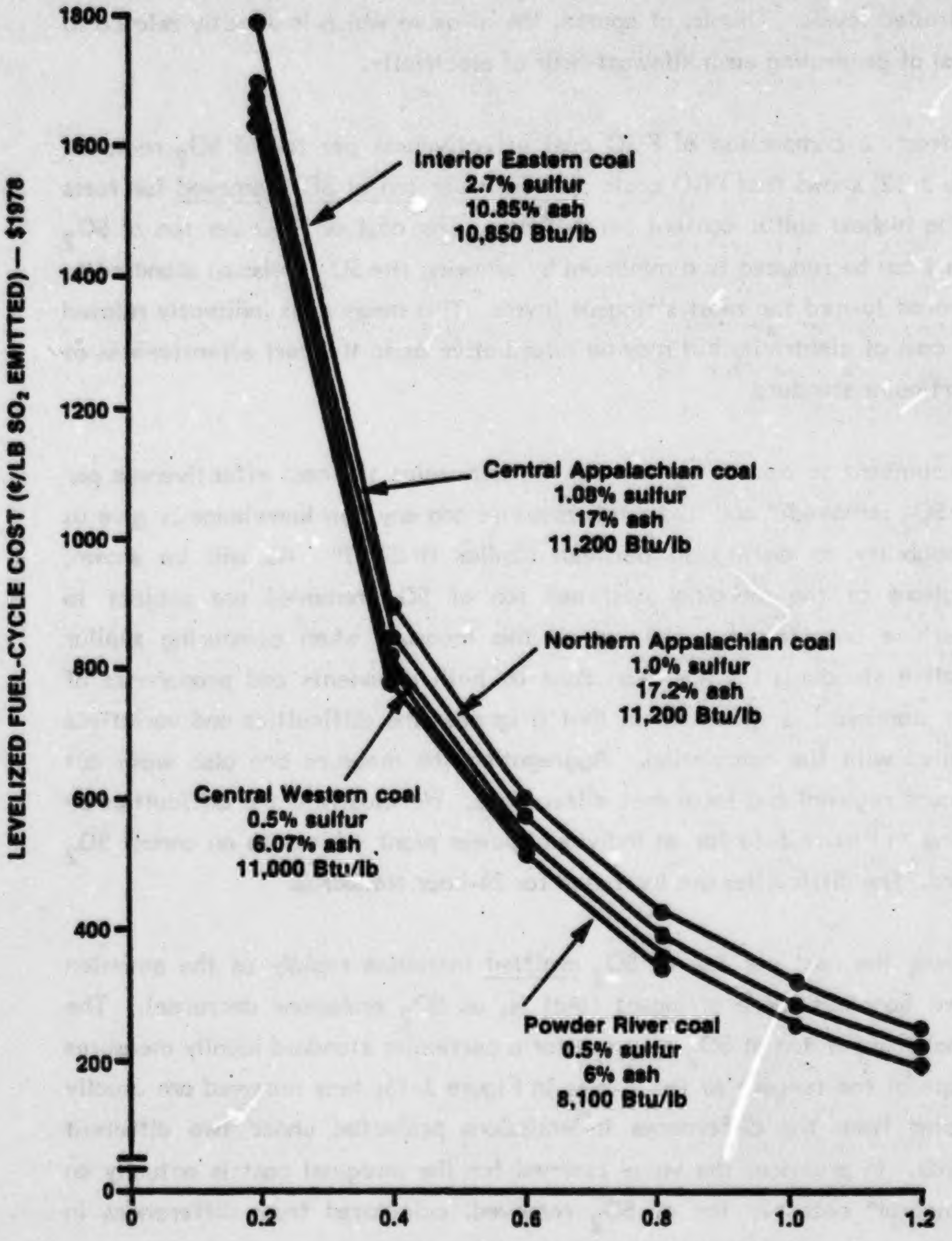
A comparison of FGD cost effectivenesss per 10^6 Btu of coal burned (Figure 3-5) shows that FGD costs can be minimized for a given standard by using the coal with the lowest sulfur content per 10^6 Btu. The cost of FGD per 10^6 Btu can be reduced to a minimum by allowing the SO_2 emission standard to increase toward uncontrolled levels. This is, of course, the measure which is directly related to the cost of generating each kilowatt-hour of electricity.

In contrast, a comparison of FGD cost effectiveness per ton of SO_2 removed (Figure 3-12) shows that FGD costs are lower per ton of SO_2 removed for fuels with the highest sulfur content per 10^6 Btu. The cost of FGD per ton of SO_2 removed can be reduced to a minimum by allowing the SO_2 emission standard to be lowered toward the most stringent levels. This measure is indirectly related to the cost of electricity but may be informative as to the cost effectiveness of any particular standard.

It is incumbent to ask, "How well can we determine the cost effectiveness per ton of SO_2 removed?" and "Does this measure add any new knowledge or give us the capability to distinguish between similar RNSPS?" As will be shown, calculations of the marginal cost per ton of SO_2 removed are subject to considerable uncertainty. Relying on this measure when comparing similar alternative standards (as has been done by both opponents and proponents of various standards) is simplistic in that it ignores the difficulties and variations associated with the calculation. Aggregating the measure can also wash out significant regional and local cost differences. We illustrate the difficulties by referring to Figure 3-13 for an individual power plant subject to an annual SO_2 standard. The difficulties are increased for 24-hour standards.

As shown, the cost per ton of SO_2 emitted increases rapidly as the emission standard becomes more stringent (that is, as SO_2 emissions decrease). The marginal cost per ton of SO_2 removed for a particular standard ideally measures the slope of the tangent to the curves in Figure 3-13; tons removed are usually calculated from the differences in emissions projected under two different standards. In practice, the value claimed for the marginal cost is actually an "incremental" cost per ton of SO_2 removed, calculated from differences in

Figure 3-13
Levelized Fuel-Cycle Costs per Pound of SO_2 Emitted as a Function of Annual SO_2 Limit (Illinois)



emissions and costs using point estimates – which do not provide good measures of the tangent. For example, consider the calculation of cost per ton removed by comparing emissions and costs under standards of 1.2, 0.6, and 0.2. Taking differences in emissions and costs at these discrete points cannot measure the true marginal costs accurately. Further, these differences are subject to considerable uncertainty and geographic variation. Because of the changing slope of the curve, calculated values can change significantly with small changes in the estimated locations of points along the curve. Indeed, each curve in Figure 3-13 is subject to uncertainty (it may be shifted right or left and up or down), and this would be the case for any particular power plant. Moreover, utility system operations (for example, whether or not the plant is baseloaded) will also influence the final shape of the curve. With aggregation of the results using a number of new power plants in different utility systems, the range of uncertainty increases and each point becomes a range of values. Taking differences at points for widely different standards does not measure marginal costs; while taking differences at points for closely similar standards belies the range of uncertainty surrounding each point.

Because of the wide variation in the cost per ton of SO_2 emitted for different power plants, and because of the inherent uncertainties in both cost and emission estimates, the usefulness of national calculations of the marginal cost per ton of SO_2 removed as a measure of individual standards is quite limited. For standards close in value, the uncertainties overwhelm our ability to distinguish a reliable cost per ton of SO_2 removed. For standards far apart, we already know that the costs per ton removed are different, and we know the direction of that difference. What cannot be measured accurately is the magnitude.

All the above considerations render comparisons of the absolute values of this measure, calculated using different national utility models (with slightly different assumptions), not at all definitive or even comparable. It is not surprising that similar alternative standards can be ranked differently using this measure. For example, the national cost effectiveness ranking presented at EPA's December 12, 1978, hearings is not especially useful, for it indicates neither the regional differences nor the ranges of uncertainty involved for any of the numerous standards that were analyzed. Nevertheless, simple cost effectiveness measures can be instructive so long as their shortcomings are recognized and use is made of a variety of different measures that are appropriate to the decision at hand.

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6. TVA-Bechtel Shawnee Limestone-Lime Computer Program: Ten printouts (lime 25 MW, 100 MW, 200 MW, 500 MW, 1000 MW; and limestone 25 MW, 100 MW, 200 MW, 500 MW, 1000 MW). Provided by C. David Stephenson, National Fertilizer Development Center, Muscle Shoals, Alabama, December 1978.

7. "Additional Information on EPA's Proposed Revision to New Source Performance Standard for Power Plants," Federal Register 43 (8 December 1978): 57834-59.

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APPENDIX A

PEDCO AND TVA FGD COSTS

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PEDCO AND TVA FGD COSTS

Teknekron has developed FGD cost and performance models based on PEDCo (February 1978) and TVA (December 1978) engineering and cost estimates for lime and limestone systems and PEDCo cost estimates for magnesium oxide systems.[4,5,6] The models can be used to predict new or retrofit FGD costs for generating plants of between 25 MW and 2,000 MW in size burning coal of any sulfur content and meeting any emission limit.

In this report, which assesses the sensitivity of projections to future FGD costs, we have referred to the PEDCo estimates as representing "higher FGD costs" and the TVA estimates as representing "lower FGD costs." The TVA and PEDCo estimates have been used to represent a reasonable range of FGD costs. The PEDCo costs are higher than TVA's and are probably representative of the cost estimates that may be used by utilities without extensive experience with FGD systems. The TVA costs, on the other hand, are less conservative and represent cost estimates that may be used in the future by utilities that have had favorable FGD experience. When similar assumptions are used, the differences between these cost estimates are reduced. These two sets of cost estimates may also be viewed as representing two points on the FGD "learning curve," with the lower cost estimates indicative of lower, future FGD costs.

The three FGD systems are modular in design, with module sizes of between 50 MW and 130 MW except for plants of less than 50 MW in size. One redundant module is included for all systems of 100 MW or greater for a design reliability of 90 percent. The design of the three FGD systems is based on a three-stage turbulent contact absorber (TCA). In determining the fuel-cycle costs of coal utilization, FGD electricity and steam costs are included in the annual operating costs. In the Utility Simulation Model, electricity and steam requirements for FGD are used to calculate plant capacity penalties. Particulate control costs are also calculated and included using the Teknekron particulate control cost and performance models developed for EPA.

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Within the model, plant characteristics, coal properties, and emission limits are used to determine the required rate of sulfur dioxide removal in pounds per hour and the required gas flow rate in actual cubic feet per minute for an FGD system having an annual average removal efficiency of 90 percent (92 percent for lime systems) or greater. If a given generating plant needs to remove less than 90 percent of the SO_2 produced to meet applicable emission limits, an FGD system with an efficiency of 90 percent will be used to scrub a portion of the flue gas. The remaining flue gas will be bypassed and mixed with the scrubbed gas to yield the required SO_2 emissions and to reduce or eliminate the fuel required for reheating the flue gas. If 90 percent or more of the SO_2 must be removed, an FGD system having the required efficiency up to the limits of technology will be used to scrub the entire flue gas stream.

The cost of such equipment as pumps, hold tanks, feed preparation equipment, and sludge ponds is based on the sulfur dioxide removal rate, while the cost of such items as fans, absorbers, and soot blowers is based on the gas flow rate. Likewise, operating costs are based on either the sulfur dioxide removal rate (e.g., raw material) or the gas flow rate (e.g., electricity, reheat steam or oil).

Outputs from the FGD model include:

- **Capital cost**
- **Fixed operating cost (independent of plant capacity factor)**
- **Variable operating cost (dependent on capacity factor)**
- **Removal efficiency**
- **Scrubber size**
- **Capacity penalty (plant capacity used to operate the FGD system)**
- **Heat rate penalty (accounts for fuel required to operate the FGD system)**
- **Water used and water cost**

- Oil used for magnesium oxide regeneration
- Oil used for reheat
- Annual sludge generation

SO_2 emissions are calculated on the basis of the uncontrolled emission rate and the required removal efficiency.

Input data required for the FGD model include:

- Individual generating-unit characteristics
  - Size
  - Age (new or retrofit)
  - Heat rate
- Coal properties
  - Heating value
  - Composition (C, H, O, N, S, H_2O, ash)
  - Class (bituminous, subbituminous, lignite)
- Environmental factors
  - Emission limit (specific limits: percentage removal, ceiling, floor, and averaging time)
- Economic factors
  - Year scrubber was built (escalation, inflation)

TVA's capital and operating cost estimates for lime and limestone FGD systems are significantly lower than PEDCo's. (Tables A-1 and A-2 illustrate the differences for a limestone system.)

The primary differences in capital cost are associated with the costs of the SO_2 scrubber, sludge pond, and contingencies and fees. The difference between the SO_2 scrubber cost estimates is due primarily to the estimates for the absorber

Table A-1

Comparison of TVA and PEDCo Limestone FGD Capital Costs[a]

Capital Cost Item	PEDCo[b]	TVA[c]
Direct Costs		
Limestone preparation	2,471,400	3,133,000
SO_2 scrubber	21,686,700	14,800,000
Sludge disposal	1,203,300	2,144,000
Sludge pond	7,108,900	0[d]
Total direct costs	32,470,300	20,077,000
Indirect costs	12,460,800	10,637,000
Contingency and fee	11,725,000	3,181,000
Working capital	0	975,000
Total capital investment	56,656,100	34,870,000

[a] Basis: Coal sulfur content = 2.76 lb S/10^6 Btu
Plant size = 500 MW
Five scrubber modules at 125 MW each
90 percent annual average FGD removal efficiency
1975 costs and dollars

[b] Adapted from raw PEDCo data for a 3-hour averaging time.

[c] Adapted from raw TVA data for a 365-day averaging time.

[d] Sludge pond capitalization included in sludge disposal operating cost (see Table A-2).

Table A-2

Comparison of TVA and PEDCo Limestone FGD Operating Costs[a]

Cost Item	PEDCo Estimate[b]			TVA Estimate[b]		
	Units Required	Unit Cost	Annual Cost	Units Required	Unit Cost	Annual Cost
Limestone	32.4 tons/hr	\$6.48/ton	\$ 1,195,500	27.5 tons/hr	\$6.00/ton	\$ 939,500
Labor	80 man-hours/day	\$7.12/MH	207,900	125 man-hours/day	\$11.00/MH	501,900
Maintenance			2,850,000			1,266,900
Overhead			1,597,600			1,256,400
Electricity	13,250 kW	25 mills/kWh	1,886,100	7320 kW	25 mills/kWh	1,042,000
Steam	92 x 10^6 Btu/hr	\$2.25/10^6 Btu	1,178,700	67 x 10^6 Btu/hr	\$2.25/10^6 Btu	858,400
Water	664.1GPM	\$0.00014/gal	32,300	545.4 GPM	\$0.00012/gal	22,400
Sludge fix chemical	9.1 tons/hr	\$14.23/ton	737,300			0
Sludge pumping	520,000 ton-miles/yr	\$1.42/ton-mile	738,400			0
Sludge disposal			0	198,300 tons/yr	\$7.50/ton	1,487,300
Total O&M costs			\$ 10,418,800			\$7,374,800

[a] Basis: Coal sulfur content = 2.76 lb S/10^6 Btu
Plant size = 500 MW
90 percent annual average FGD removal efficiency
Capacity factor = 0.65
1975 costs and dollars

[b] Adapted from raw PEDCo and TVA data.

and not to the estimates for the various peripheral items, such as pumps, motors, fans, and reheaters. As for the sludge pond, PEDCo estimates a capital cost of about $7.1 million, while TVA includes sludge pond capitalization in the sludge disposal cost. Finally, with respect to contingency and fee, PEDCo assumes a 20 percent contingency and a 6 percent fee on both direct and indirect capital costs, while TVA assumes a contingency equal to 10 percent of the direct investment and a fee of 5 percent of the direct investment.

The primary differences in the PEDCo and TVA operating cost estimates are in the cost of maintenance and electricity. Both PEDCo and TVA maintenance costs are based on a percentage of the capital cost. PEDCo's maintenance-cost estimates are higher than TVA's because of PEDCo's higher capital costs and somewhat higher percentage. Electricity costs depend directly on system configuration and estimated motor sizes and duty cycles. The TVA system is more efficiently designed in this regard, resulting in significantly lower electricity requirements.

Overall, the PEDCo cost estimates reflect design conservatism and are typical of estimates that could be used by utilities that wish to be conservative in their estimates of FGD system costs. The TVA costs, on the other hand, reflect a greater confidence in the design basis for FGD systems and are less conservative than the current PEDCo estimates.

Capital and operating costs for full limestone scrubbing on a 500 MW plant, calculated by Teknekron's SO_2 control cost model using PEDCo and TVA costs, are shown in Tables A-3 and A-4. The PEDCo versus TVA-cost differences in these tables are similar to those in Tables A-1 and A-2.

The cost of electricity and steam required to operate the FGD system is not calculated in the Teknekron SO_2 model; instead, electricity and steam requirements are used to calculate unit capacity penalties and are accounted for in this manner by the Utility Simulation Model. For the case illustrated in Tables A-3 and A-4, the TVA capacity penalty is 2.96 percent, and the PEDCo capacity penalty is 4.25 percent.

Table A-3

Comparison of Modeled TVA and PEDCo Limestone FGD Capital Costs[a]

Capital Cost Item	PEDCo[b]	TVA[b]
Direct costs		
Limestone preparation	$ 2,423,800	$ 3,322,100
SO_2 scrubber	21,012,600	14,786,800
Sludge disposal	1,201,900	2,248,900
Sludge pond	5,632,800	0[c]
Raw material inventory	162,600	0
Total direct costs	$30,433,700	$20,357,800
Indirect costs	9,271,900	7,348,700
Contingency and fee	10,283,000	3,053,700
Total capital investment	$49,988,600	$30,760,200

Note: More recent estimates by TVA include about $7 million for the sludge pond and a contingency and fee of 25 percent of total direct costs. Total TVA investment is therefore increased to about $42 million.

[a] Basis: Coal sulfur content = 2.50 lb S/10^6 Btu
Sulfur RSD = 0.15, no exemptions
Design sulfur content = 3.63 lb S/10^6 Btu
Plant size = 500 MW
Five scrubber modules at 125 MW each
85 percent 24-hour average SO_2 removal
1975 costs and dollars

[b] Costs predicted by Teknekron's SO_2 control model. Not included are interest during construction, working capital, and taxes; these are calculated in the Utility Simulation Model's financial module.

[c] Sludge pond capitalization included in sludge disposal operating cost (see Table A-4).

Table A-4

Comparison of Modeled TVA and PEDCo Limestone FGD Operating Costs[a]

Cost Item	PEDCo[b]	TVA[b]
Limestone	$ 804,400	$ 769,900
Labor	406,500	783,400
Maintenance	3,736,600	1,816,800
Water	38,000	21,800
Sludge disposal	996,100	1,219,700
Analysis cost	0	69,400
Total O&M costs	$5,981,600	$4,684,000

Note: More recent estimates by TVA include a higher cost for maintenance (due to higher capital cost) and sludge disposal. Total TVA operating cost estimates are about the same as the PEDCo estimates.

[a] Basis: Coal sulfur content = 2.50 lb S/10^6 Btu
Plant size = 500 MW
85 percent 24-hour average SO_2 removal
Capacity factor = 0.65
1975 costs and dollars

[b] Costs predicted by Teknekron's SO_2 control model. Not included are: (a) steam and electricity costs, which are used in the Utility Simulation Model to calculate capacity penalties; and (b) fixed charges, which are calculated in the Utility Simulation Model's financial module.

APPENDIX B

LIFE-CYCLE COSTING

APPENDIX B

LIFE-CYCLE COSTING

When faced with an investment decision, an industrial firm usually compares the present values of all costs (operating as well as capital costs) associated with each alternative investment under consideration. It is common to think of the cost of alternative systems in terms of annual costs over the economic life of a facility. Within the present-value framework, this can be done by levelizing capital and operating expenditures and then comparing between alternatives, choosing those that have the lowest levelized capital and operating cost.

In levelizing, one derives a series of equivalent annual costs that gives the same present value as a series of varying annual operating costs or one-time capital costs that are expected to occur. By definition, each annual term in the levelized series is equivalent; the levelized cost is thus equal to the value of any one of the terms in the series. Mathematically, present value is represented as:

$$PV_j = \frac{C_j(1 + p_j)}{1 + d} + \frac{C_j(1 + p_j)(1 + p_{j+1})}{(1 + d)^2} + \ldots + \frac{C_j(1 + p_j) \ldots (1 + p_{j+N})}{(1 + d)^N}, \quad (1)$$

where

PV_j = present value of variable being evaluated in initial year j,

C_j = cost of variable being evaluated in initial year j (beginning of the year),

p_j = price escalation of that variable in year j,

N = economic lifetime,

d = average discount rate over time period considered = weighted average cost of corporate capital.

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The levelized cost is related to the present value as follows:

$$LC = \frac{d(1 + d)^N}{(1 + d)^N - 1} PV_j, \qquad (2)$$

where

LC = levelized cost of variable being levelized.

For operating costs, an equivalent way to derive LC is to calculate a levelization factor which, when multiplied by the cost in the initial year j, will yield LC. This levelization factor is calculated by using the following formula:

$$LF = \left[\frac{d(1 + d)^N}{(1 + d)^N - 1}\right]\left[\frac{1 + p}{d - p}\right]\left[1 - \frac{1 + p}{1 + d}\right]^N, \qquad (3)$$

where

LF = levelization factor,

p = average price escalation rate for entire time period N.

In practice and in our applications, p is not necessarily constant. The use of these formulae in levelizing operating costs is illustrated in Tables B-1 and B-2.

For capital costs, there are additional charges associated with an investment beyond the initial ones levelized by applying equation (2). The taxes and insurance required for capital equipment should be accounted for as well. This is usually done by applying a fixed charge rate to the initial investment amount rather than using equation (2) to arrive at a total levelized cost associated with capital expenditures. The fixed charge rate is defined as

$$FCR = WACC + DEPR_{CR} + TAX + IRT, \qquad (4)$$

where

FCR = fixed charge rate,

WACC = weighted average cost of capital,

Table B-1

Calculation of Present Value

	Initial-Year Cost		Price Escalation Factor		Escalated Cost		Discount Factor		Present Value
Year	C	x	$(1 + p)^N$	=	C_E, C_E	x	$\frac{1}{(1 + d)^N}$	=	PV
1	1		1.0700		1.0700		.9091		.9727
2	1		1.1449		1.1449		.8264		.9462
3	1		1.2250		1.225		.7513		.9204
4	1		1.3108		1.3108		.6830		.8953
Total	1								3.7346[a]

Note: p = annual price escalation rate; N = number of years; d = discount rate.

[a] Present value is the same, whether calculated by this long method or by the method of discounting levelized costs shown in Table B-2.

Table B-2

Calculation of Present Value by Discounting Levelized Costs

	Initial-Year Cost		Levelization Factor		Levelized Cost		Discount Factor		Present Value
Year	C	x	LF	=	LC, LC	x	$\frac{1}{(1+d)^N}$	=	PV
1	1		1.1782		1.1782		.9091		1.0710
2	1		1.1782		1.1782		.8264		.9737
3	1		1.1782		1.1782		.7513		.8852
4	1		1.1782		1.1782		.6830		.8047
Total									3.7346[a]

Note: $$LF = \left[\frac{d(1+d)^N}{(1+d)^N - 1}\right] \left[\frac{1+p}{d-p}\right] \left[1 - \left(\frac{1+p}{1+d}\right)^N\right].$$

[a] Present value is the same, whether calculated by this method or by the long method in Table B-1.

Note also that $LC = PV \times \frac{d(1+d)^N}{(1+d)^N - 1} = 3.7346 \times .3155 = 1.1782.$

DEPR_{CR} = depreciation for capital recovery as a levelized percentage of initial investment,

TAX = taxes as a levelized percentage of initial investment,

IRT = insurance and real estate taxes as a percentage of initial investment.*

Because of the lower cost of capital associated with pollution control investments, the fixed charge rate used to evaluate such an investment by a privately owned utility is usually lower than the rate used for other investments. The fixed charge rates and levelization factors used in the analyses contained in this report are presented in Table B-3, and the cost elements of the coal fuel cycle that are levelized are shown in Table B-4.

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*Sometimes equation (4) is written as

$$\text{FCR} = \text{CRF} + \text{TAX} + \text{IRT},$$

where

$$\begin{aligned}\text{CRF} &= \text{capital recovery factor}\\ &= \text{WACC} + \text{DEPR}_{CR},\end{aligned}$$

and where DEPR_{CR} is calculated by the sinking fund formula as

$$\text{DEPR}_{CR} = \frac{\text{WACC}}{(1 + \text{WACC})^N - 1}$$

Then:

$$\text{WACC} + \text{DEPR}_{CR} = \text{WACC} + \frac{\text{WACC}}{(1 + \text{WACC})^N - 1} = \frac{\text{WACC}\,(1 + \text{WACC})^N}{(1 + \text{WACC})^N - 1}\,.$$

This last expression, when multiplied by the initial investment, is equivalent to LC calculated in equation (2).

Table B-3

Fixed Charge Rates and Levelization Factors Used to Evaluate Investments in Publicly and Privately Owned Electric Utilities[a]

Variable	Public Ownership	Private Ownership	Pollution Control Investment (Private Ownership)
Fixed charge rate	11.3 %	20.1 %	19.4 %
Levelization factor	1.94	1.73	1.73

[a] Assuming a plant life of 30 years.

Table B-4

Costs Levellized in the Coal Fuel Cycle

Capital Costs

- Electrostatic precipitator
- Fabric filter
- Flue Gas Desulfurization
- Boiler

Operating Costs

- F.o.b. mine price
- Transportation cost
- Coal cleaning cost (if applicable)
- Particulate control O&M
- Flue gas desulfurization O&M

It is also important to examine the sensitivity of levelized costs with respect to various parameters of the life-cycle costing formulation. A simplifying assumption that can be used to determine operating cost sensitivity, as discussed in this appendix, is to allow the average discount rate over time to be equal to the average price escalation rate. This produces the largest sensitivities to be expected. Numerical sensitivities can be examined, since equation (3) then reduces to:

$$LF/_{p=d} = \frac{Nd\,(1 + d)^{N-1}}{(1 + d)^{N} - 1} \qquad (5)$$

Selected numerical values for price escalation and economic lifetime when applied to equation (5) are shown in Table B-5. This information shows that levelized operating costs may vary considerably — in this worst-case analysis — depending on both the economic lifetime and the average price escalation to be expected.

The sensitivity of life-cycle cost to capital costs is directly dependent on the fixed charge rate assumed. Values assumed in this analysis are shown in Table B-3. The overall life-cycle cost is the sum of capital and operating costs, so that the sensitivity of key parameters to total cost must be considered on a specific basis. For example, if 60 percent of the total levelized cost were capital-related, the variations shown in Table B-5 would apply to only 40 percent of the cost.

Table B-5

Sensitivity of Levelization Factors

N	p = d	
	8%	12%
20	1.8	2.39
25	2.17	2.85
30	2.47	3.33

APPENDIX C

CITY-SPECIFIC SENSITIVITY ANALYSES

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APPENDIX C
CITY-SPECIFIC SENSITIVITY ANALYSES

In order to demonstrate regional implications of the various sensitivity analyses conducted in this study, several city-specific cases are presented in this appendix. The case for Columbus, Ohio, is presented in detail in the text.

This appendix includes graphic presentations of the sensitivity analyses for the following key factors as a function of the SO_2 standard (considering both the standard with a 24-hour floor and that with an annual ceiling):

- F.o.b. coal mine prices
- Coal transportation rates
- Western coal sulfur and Btu characteristics

The key cities covered here are:

- Indianapolis, Indiana
- Orlando, Florida
- Austin, Texas

Together with Columbus, Ohio, they are representative of a range of geographical and other differences.

24-Hour SO_2 Standard

Sensitivity to Coal Mine Price

The sensitivity of fuel-cycle costs with respect to the 24-hour SO_2 floor and f.o.b. coal mine price is shown for Indiana, Florida, and Texas in Figures C-1 through C-3.

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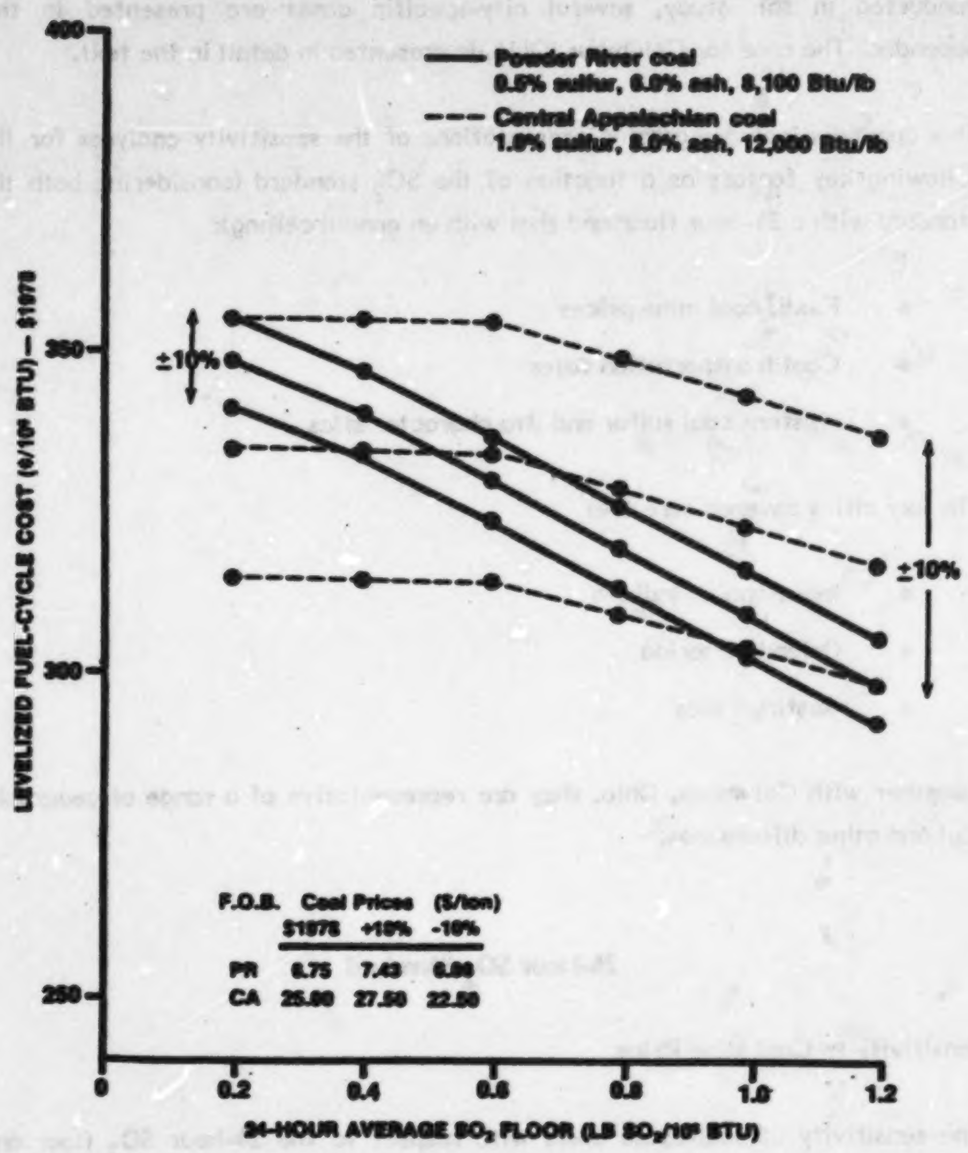
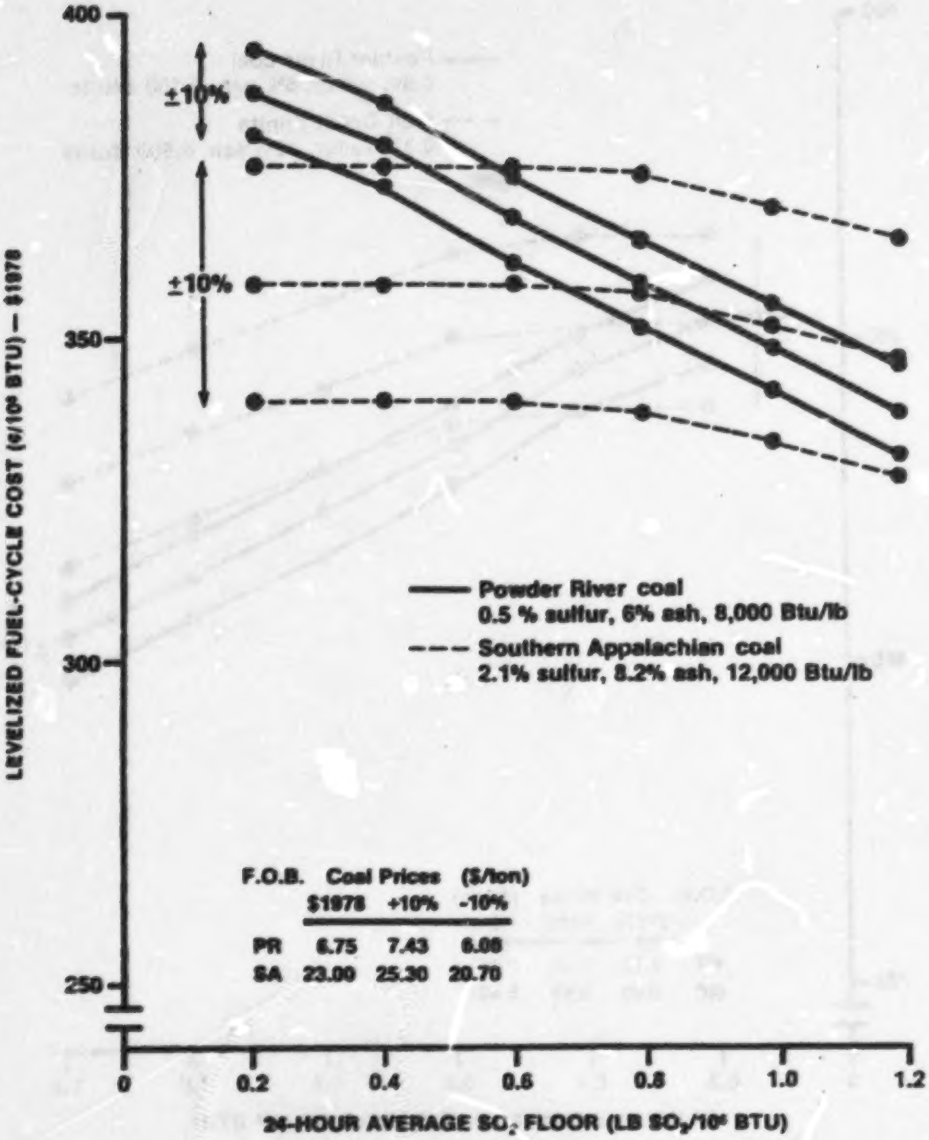
Figure C-1
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and F.O.B. Coal Mine Prices
(Indianapolis, Indiana)



F.O.B.	Coal Prices	($/ton)	
	$1978	+10%	-10%
PR	6.75	7.43	6.08
CA	25.00	27.50	22.50

Note: **Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month). Transportation rates: rail < 250 miles, 2.25¢/ton-mile; > 250 miles, 1.20¢/ton-mile; water 0.5¢/ton-mile.**

Figure C-2
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and F.O.B. Coal Mine Prices
(Orlando, Florida)

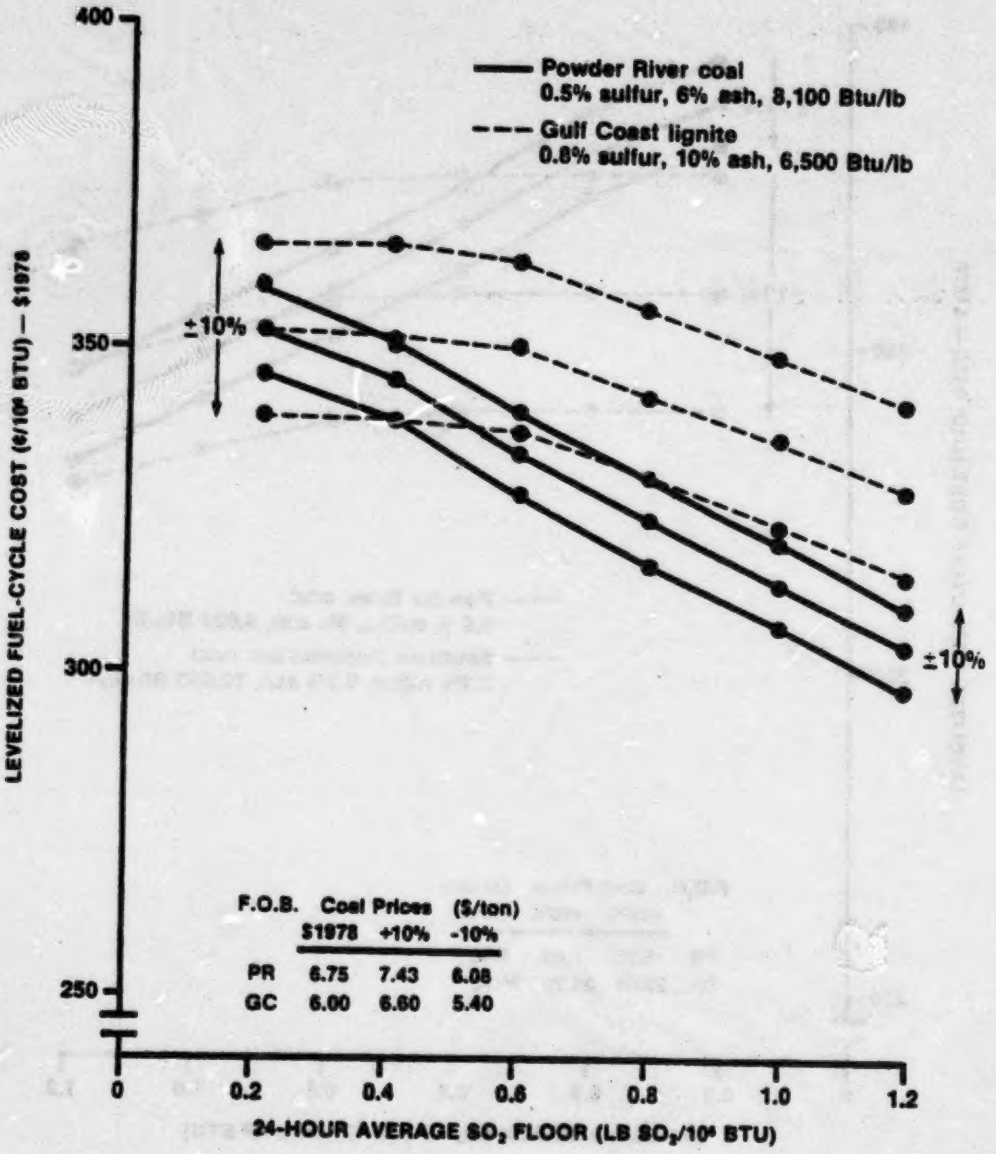


F.O.B. Coal Prices ($/ton)

	$1978	+10%	-10%
PR	6.75	7.43	6.08
SA	23.00	25.30	20.70

Note: **Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month). Transportation rates: rail < 250 miles, 2.25¢/ton-mile; > 250 miles, 1.20¢/ton-mile; water 0.5¢/ton-mile.**

Figure C-3
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and F.O.B. Coal Mine Prices
(Austin, Texas)



F.O.B.	Coal Prices $1978	+10%	($/ton) -10%
PR	6.75	7.43	6.08
GC	6.00	6.60	5.40

Note: Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month). Transportation rates: rail < 250 miles, 2.25¢/ton-mile; > 250 miles, 1.20¢/ton-mile; water 0.5¢/ton-mile.

Western coal becomes increasingly competitive at all floors as coal mine prices uniformly escalate. That is, the floor above which western coal is economically preferred decreases as the relative coal price increases, as shown in Table C-1.

Table C-1

24-Hour SO_2 Floors above Which Western Coal Is Economically Preferred for Various Coal Mine Prices

	F.o.b. Mine Price		
	+10%	1978 Level	-10%
Ohio (Columbus)	~0.7	~0.9	~1.2
Indiana (Indianapolis)	~0.2	~0.5	~0.9
Florida (Orlando)	~0.6	~0.8	>1.2
Texas (Austin)	~0.2	<0.2	~0.4

For this analysis, as shown in Figures C-1 through C-3, the following f.o.b. coal mine prices were assumed:

	F.o.b. Coal Mine Prices (1978 $/ton)		
	Base Price	+10%	-10%
Powder River (PR)	6.75	7.43	6.08
Northern Appalachian (NA)	23.00	25.30	20.70
Central Appalachian (CA)	25.00	27.50	22.50
Southern Appalachian (SA)	23.00	25.30	20.70
Gulf Coast Lignite (GC)	6.00	6.60	5.40

Thus, general inflation in coal mining cost tends to favor distant western coals. This is because the proportion of coal mine price to total cost is much smaller for these than for local coals. However, even though escalating coal mine price favors western coals, whether or not these coals are chosen by a utility depends on plant location and other site-specific factors as well as on the level of the applicable SO_2 standard.

Sensitivity to Coal Transportation Rate

The sensitivity of fuel-cycle costs with respect to the 24-hour SO_2 floor and coal transportation rate is shown for Indiana, Florida, and Texas in Figures C-4 through C-6.

Escalating rail and barge rates favor local coals, causing them to become increasingly competitive at all floors. That is, the emission floor above which western coal is economically preferred increases as transportation rates increase, as shown in Table C-2.

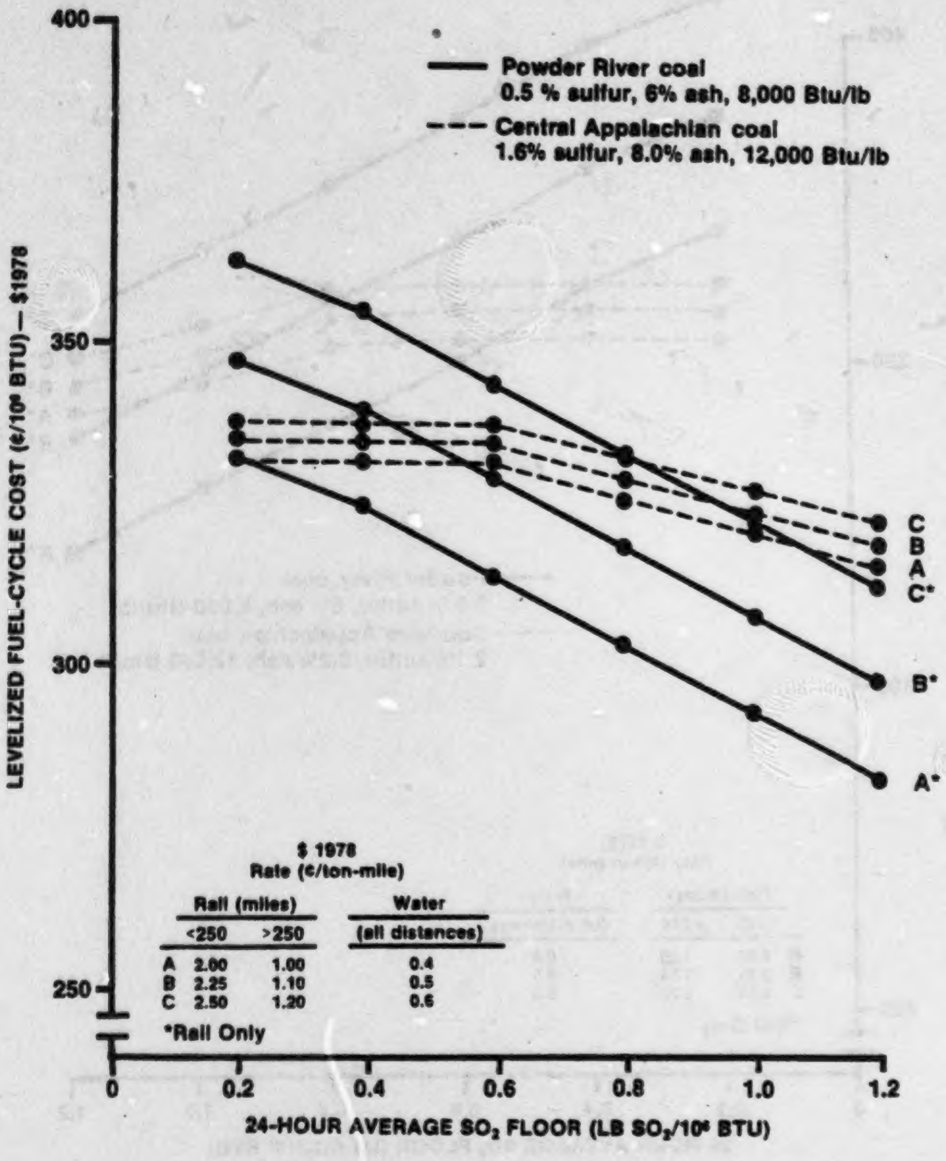
Table C-2

24-Hour SO_2 Floors above Which Western Coal Is Economically Preferred for Various Transportation Rates

	Lowest Rate (A)	Medium Rate (B)	Highest Rate (C)
Ohio (Columbus)	~0.6	~0.9	>1.2
Indiana (Indianapolis)	>0.2	~0.5	~0.8
Florida (Orlando)	~0.5	~0.9	>1.2
Texas (Austin)	~0.6	>1.2	>1.2

This is because the proportion of transportation cost to total cost is much smaller for local than for western coals. The following coal transportation rates were assumed for the sensitivity analyses:

Figure C-4
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and Transportation Rate
(Indianapolis, Indiana)



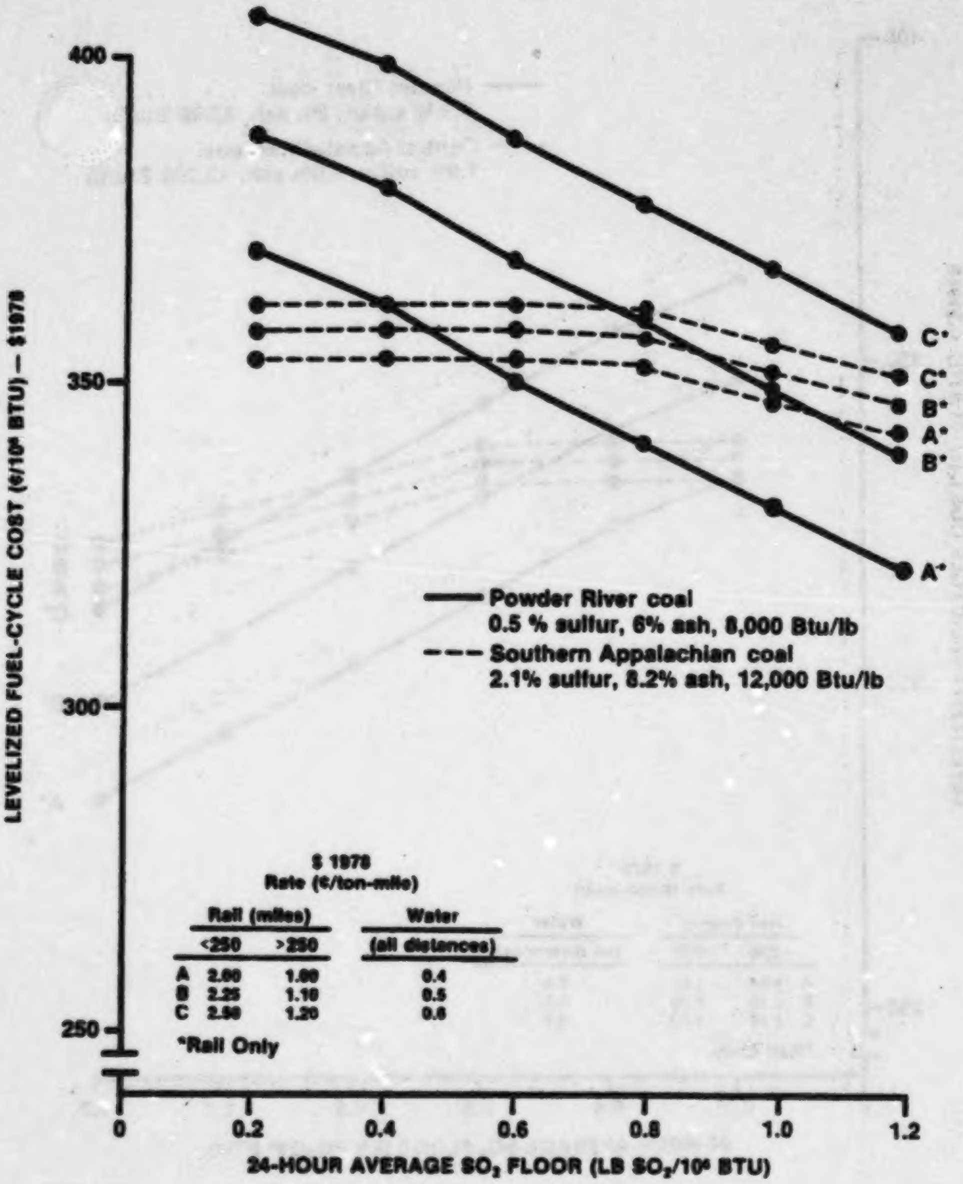
$ 1978
Rate (¢/ton-mile)

	Rail (miles)		Water
	<250	>250	(all distances)
A	2.00	1.00	0.4
B	2.25	1.10	0.5
C	2.50	1.20	0.6

*Rail Only

Note: Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month).

Figure C-5
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and Transportation Rate
(Orlando, Florida)



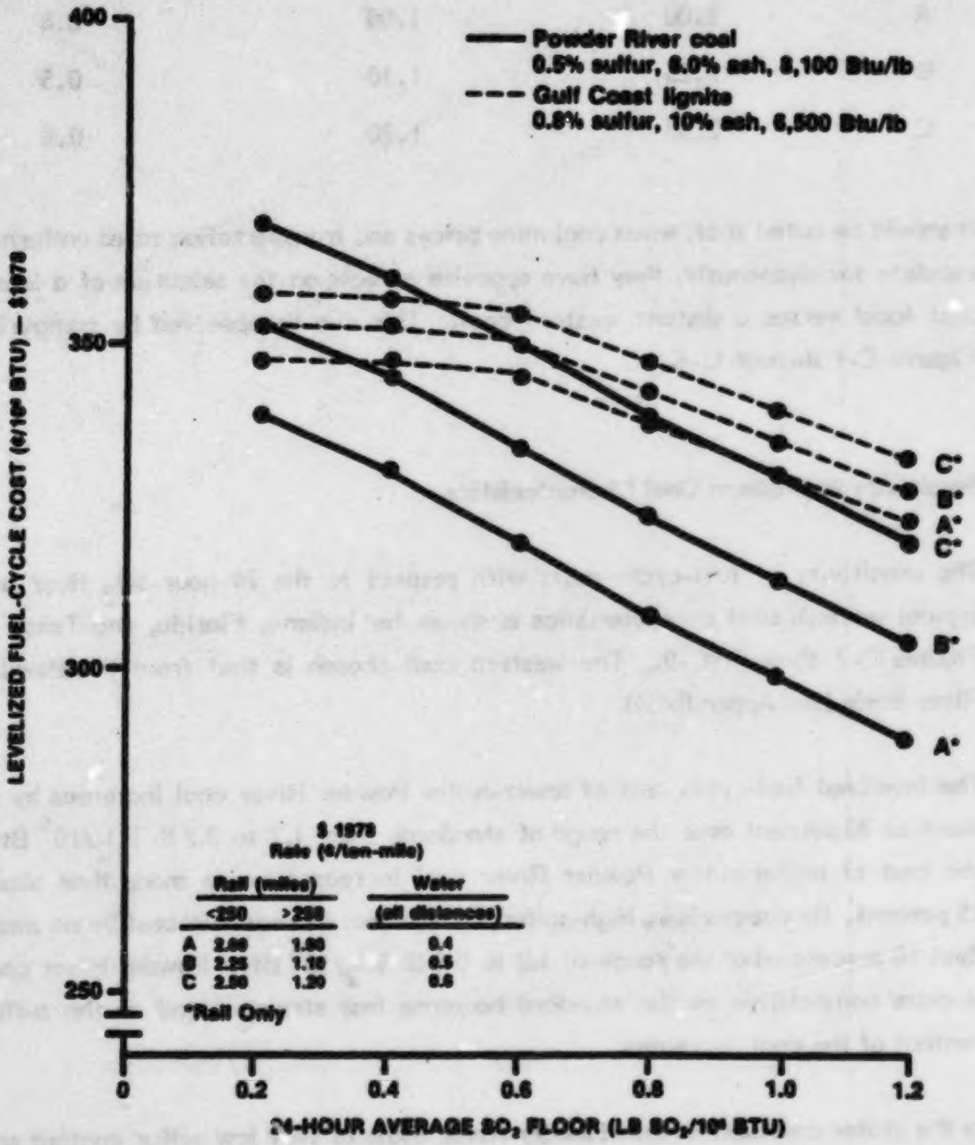
$ 1978
Rate (¢/ton-mile)

	Rail (miles)		Water
	<250	>250	(all distances)
A	2.00	1.00	0.4
B	2.25	1.10	0.5
C	2.50	1.20	0.6

*Rail Only

Note: **Calculations assume a 1.2 lb SO_2/10^6 Btu ceiling with 85% removal (24-hour average with exemptions of three days per month).**

Figure C-6
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and Transportation Rate
(Austin, Texas)



$ 1978
Rate (¢/ton-mile)

	Rail (miles)		Water
	<250	>250	(all distances)
A	2.00	1.00	0.4
B	2.25	1.10	0.5
C	2.50	1.20	0.6

*Rail Only

Note: **Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month).**

Coal Transportation Rate (1978 ¢/ton-mile)

	RAIL (miles)		WATER
	<250	>250	(all distances)
A	2.00	1.00	0.4
B	2.25	1.10	0.5
C	2.50	1.20	0.6

It should be noted that, when coal mine prices and transportation rates uniformly escalate simultaneously, they have opposite effects on the selection of a least-cost local versus a distant western coal. This can be observed by comparing Figures C-1 through C-6.

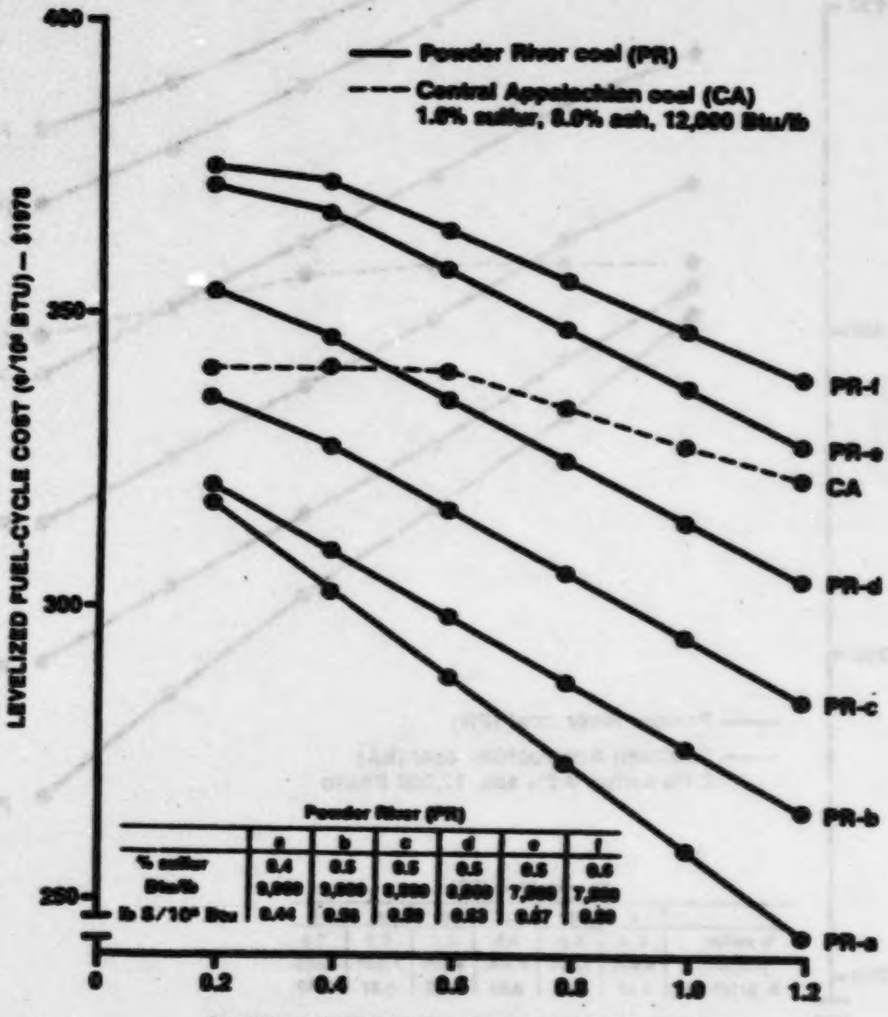
Sensitivity to Western Coal Characteristics

The sensitivity of fuel-cycle costs with respect to the 24-hour SO_2 floor and typical western coal characteristics is shown for Indiana, Florida, and Texas in Figures C-7 through C-9. The western coal chosen is that from the Powder River Basin (see Appendix D).

The levelized fuel-cycle cost of lower-sulfur Powder River coal increases by as much as 30 percent over the range of standards from 1.2 to 0.2 lb $SO_2/10^6$ Btu; the cost of higher-sulfur Powder River coal increases by no more than about 15 percent. By comparison, high-sulfur eastern coal increases in cost by no more than 10 percent over the range of 1.2 to 0.2 lb $SO_2/10^6$ Btu. Powder River coal is more competitive as the standard becomes less stringent and as the sulfur content of the coal decreases.

In the states considered here, Powder River coals of very low sulfur content are preferred to local coals at every floor within the range of 1.2 to 0.2 lb $SO_2/10^6$ Btu. Conversely, Powder River coals of very high sulfur content are not likely to

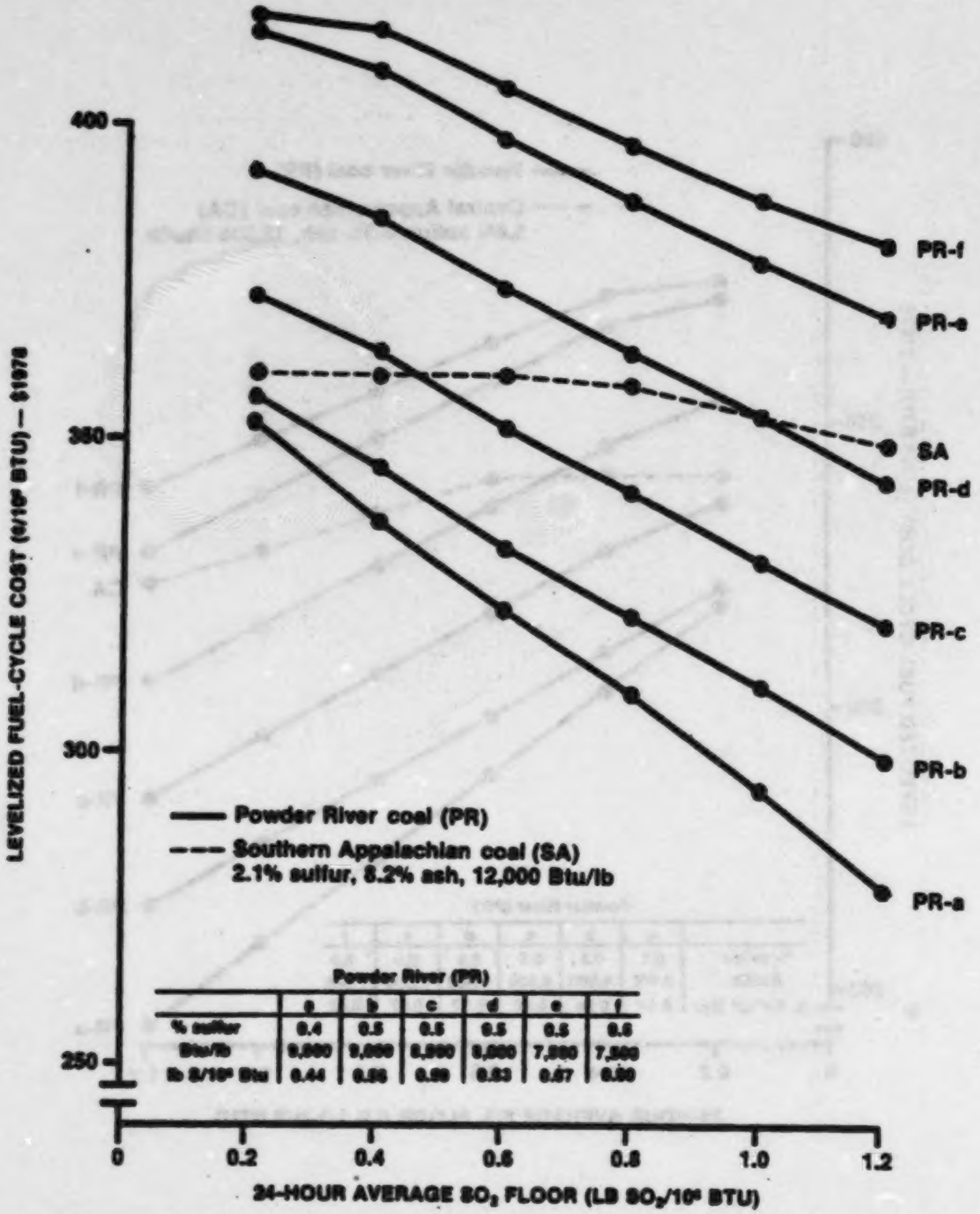
Figure C-7
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and Powder River Coal Characteristics
(Indianapolis, Indiana)



	Powder River (PR)					
	a	b	c	d	e	f
% sulfur	0.4	0.5	0.5	0.5	0.5	0.6
Btu/lb	9,000	9,000	8,500	8,000	7,500	7,500
lb S/10^6 Btu	0.44	0.56	0.59	0.63	0.67	0.80

Note: Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month). Powder River $1978/ton = 6.75; Central Appalachian $1978/ton = 25.00.

Figure C-8
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO_2 Floor and Powder River Coal Characteristics
(Orlando, Florida)

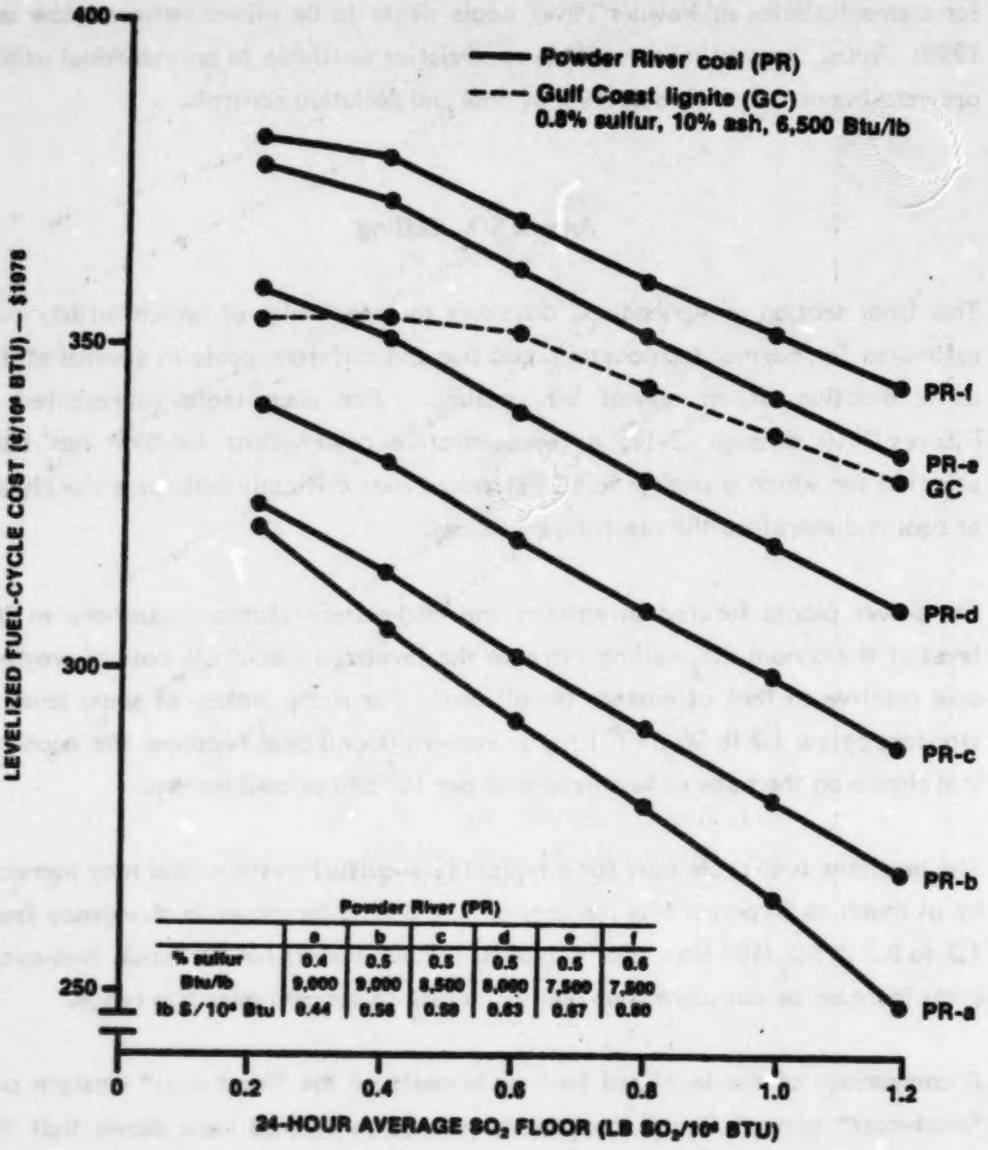


Powder River (PR)

	a	b	c	d	e	f
% sulfur	0.4	0.5	0.5	0.5	0.5	0.6
Btu/lb	9,000	9,000	8,500	8,000	7,500	7,500
lb S/10⁶ Btu	0.44	0.56	0.59	0.63	0.67	0.80

Note: Calculations assume a 1.2 lb $SO_2/10^6$ Btu ceiling with 85% removal (24-hour average with exemptions of three days per month). Powder River $1978/ton = 6.75; Southern Appalachian $1978/ton = 23.00.

Figure C-9
Sensitivity of Levelized Fuel-Cycle Cost to 24-Hour SO$_2$ Floor and Powder River Coal Characteristics
(Austin, Texas)



Powder River (PR)

	a	b	c	d	e	f
% sulfur	0.4	0.5	0.5	0.5	0.5	0.6
Btu/lb	9,000	9,000	8,500	8,000	7,500	7,500
lb S/10^6 Btu	0.44	0.56	0.59	0.63	0.67	0.80

Note: **Calculations assume a 1.2 lb SO$_2$/10^6 Btu ceiling with 85% removal (24-hour average with exemptions of three days per month). Powder River coal $1978/ton = 6.75; Gulf Coast lignite $1978/ton = 10.00.**

be selected as the least-cost coal for any level of floor. Figures C-7 through C-9 indicate that the following Powder River coals are of "minimum competitive quality": For Indiana, 0.60 lb S/10^6 Btu; for Florida, 0.57 lb S/10^6 Btu; and for Texas, 0.62 lb S/10^6 Btu. It should be noted that the average sulfur content of the Wodak-Anderson seam is approximately 0.61 lb S/10^6 Btu (see Appendix D for characteristics of Powder River coals likely to be mined between now and 1990). Thus, the particular coal characteristics available to an individual utility are very important to its selection of coal and pollution controls.

Annual SO_2 Ceiling

This final section of Appendix C discusses the sensitivity of typical utility cost estimates for buying, transporting, and burning different coals in several states as a function of an annual SO_2 ceiling. For each state represented in Figures C-10 through C-12, a representative power-plant location has been selected for which a change in SO_2 standard may critically influence the choice of coal and therefore the resulting emissions.

For power plants located in eastern and midwestern states, reductions in the level of the annual SO_2 ceiling increase the levelized fuel-cycle cost of western coal relative to that of eastern (local) coal. For many states, at some level of standard below 1.2 lb $SO_2/10^6$ Btu, an eastern (local) coal becomes the economical choice on the basis of levelized cost per 10^6 Btu of coal burned.

The levelized fuel-cycle cost for a typical (low-sulfur) western coal may increase by as much as 30 percent as the annual SO_2 ceiling increases in stringency from 1.2 to 0.2 lb $SO_2/10^6$ Btu. For a typical (higher-sulfur) eastern coal, fuel-cycle costs increase by not more than approximately 15 percent over this range.

A comparison of the levelized fuel-cycle costs of the "least-cost" western and "least-cost" eastern (local) coal in the states considered here shows that the differences do not exceed approximately ± 15 percent. These states represent sufficient geographic diversity to suggest this conclusion on a national basis.

Figure C-10
Sensitivity of Levelized Fuel-Cycle Cost to Annual SO_2 Ceiling
(Indianapolis, Indiana)

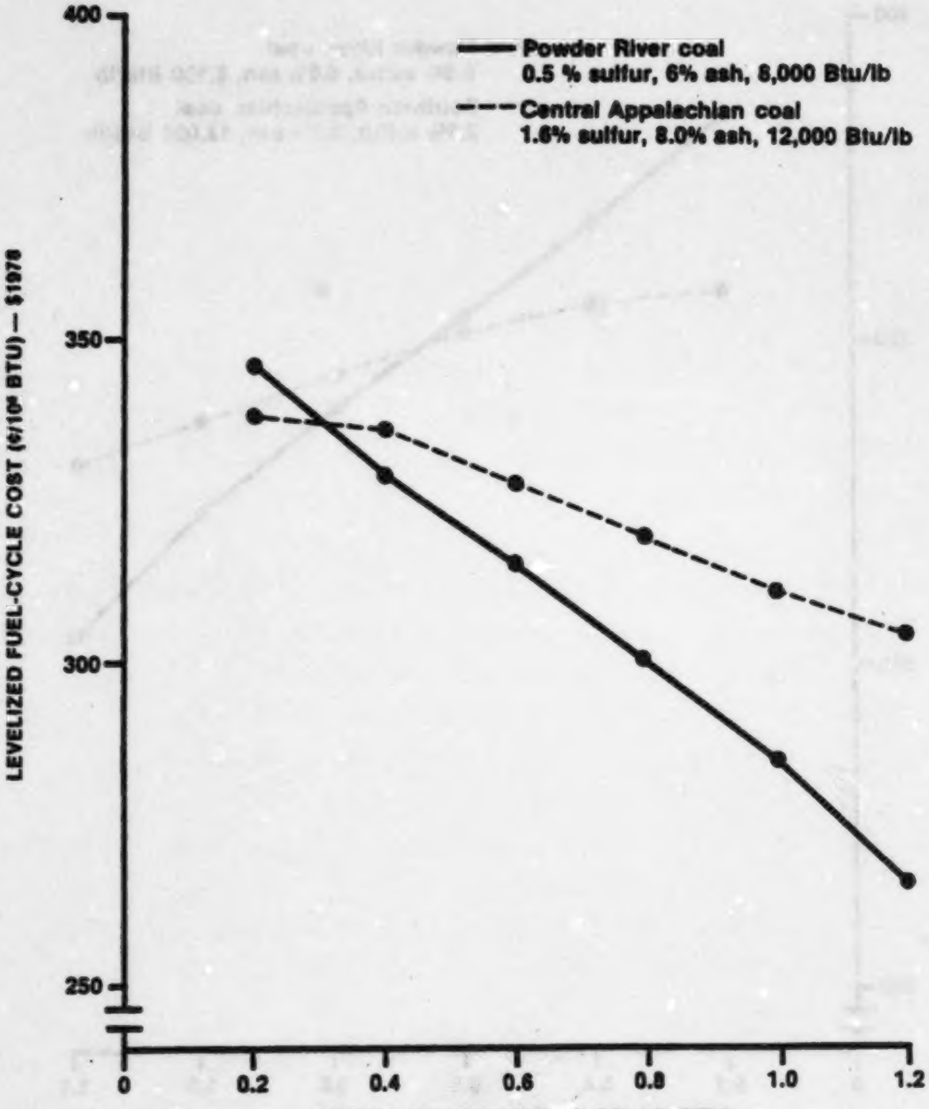


Figure C-11
Sensitivity of Levelized Fuel-Cycle Cost to Annual SO_2 Ceiling
(Orlando, Florida)

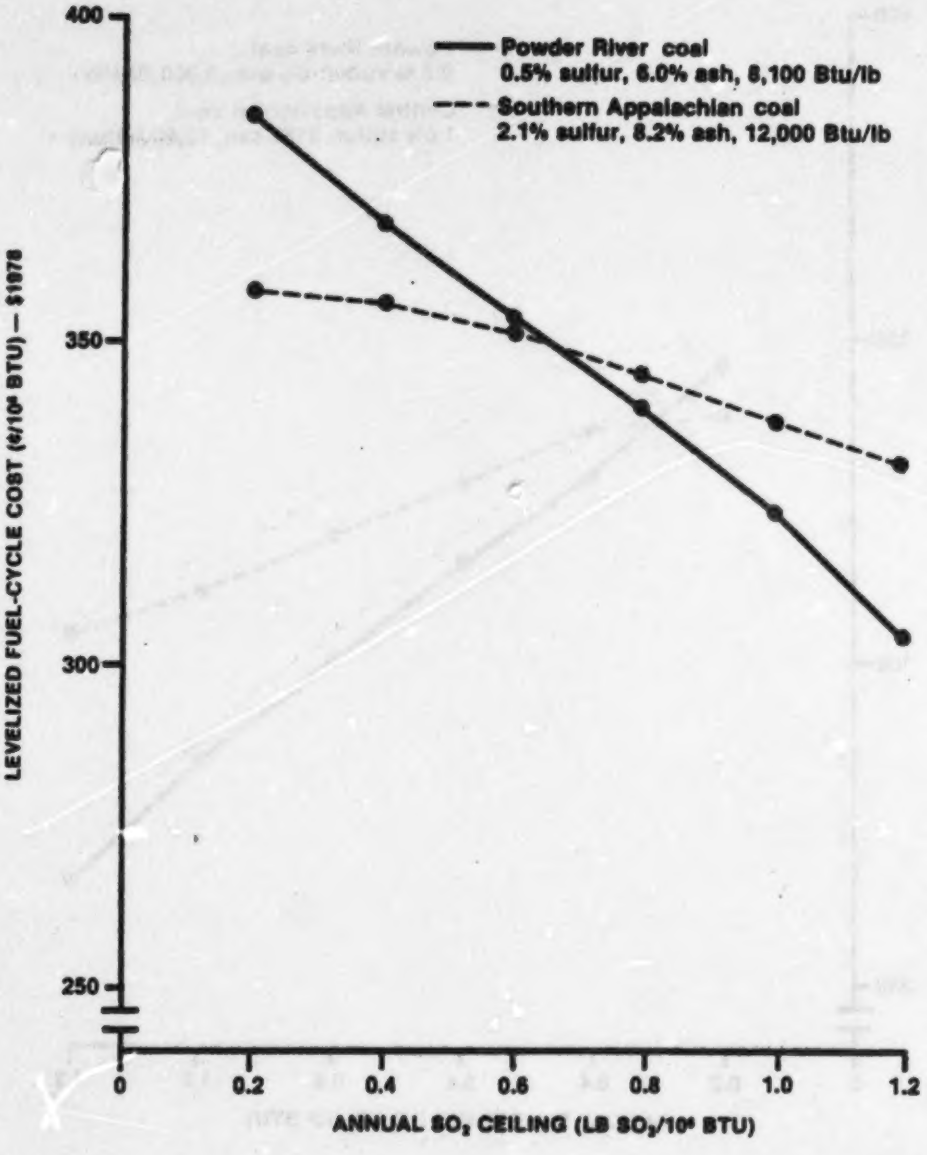
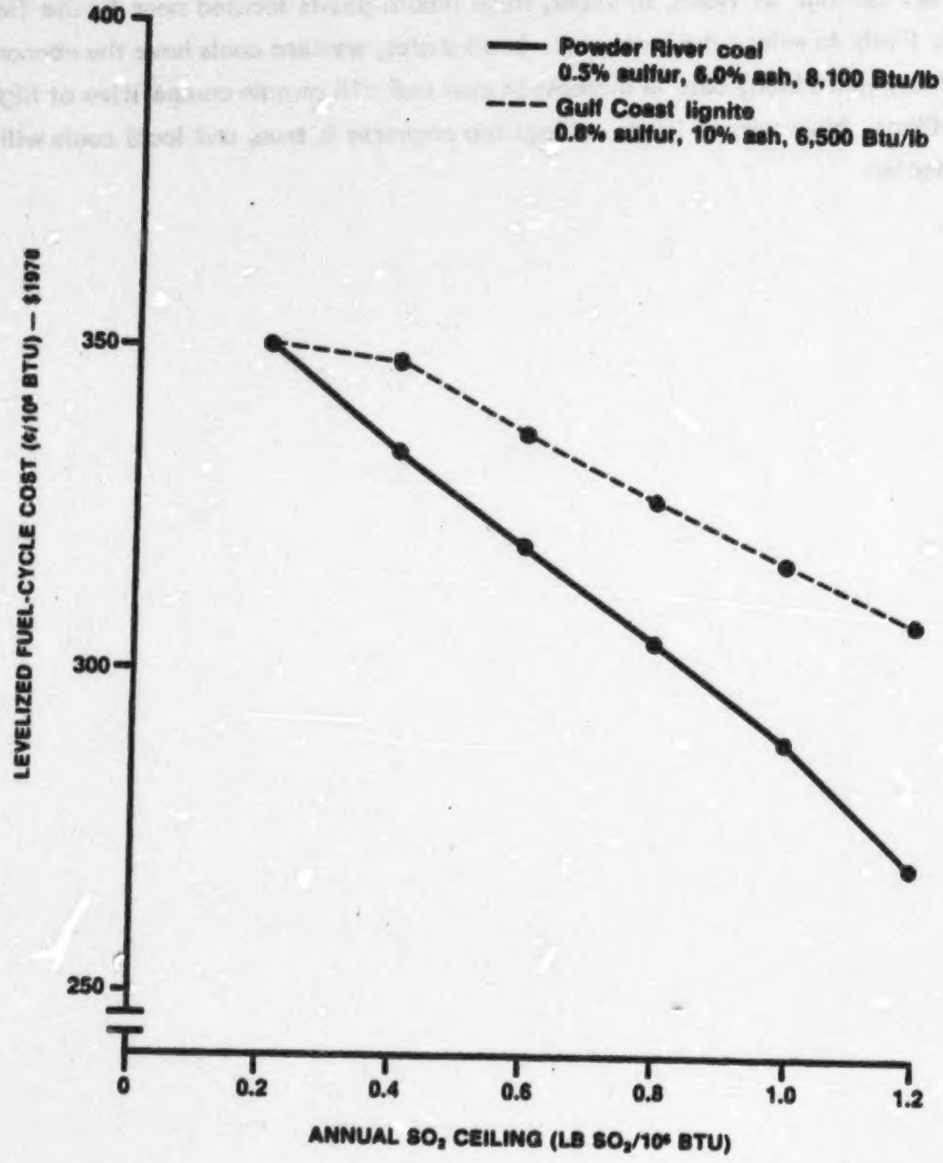


Figure C-12
Sensitivity of Levelized Fuel-Cycle Cost to Annual SO_2 Ceiling (Austin, Texas)



For the city-specific data selected for Ohio (see Section 3) and Florida (Figure C-10), eastern (local) coals are preferred at ceilings below about 0.65 and have the economic advantage of being able to increase in cost by as much as 8 percent and still remain the preferred least-cost coal. In Indiana (Figure C-11) and Texas (Figure C-12), western coals (Powder River) are preferred at nearly every ceiling. In Texas, however, mine mouth plants located near lignite fields are likely to select the local coal. In all states, western coals have the economic advantage of being able to increase in cost and still remain competitive at higher ceilings. However, at lower ceilings the converse is true, and local coals will be selected.

APPENDIX D

CHARACTERISTICS OF MAJOR POWDER RIVER BASIN COAL SEAMS

APPENDIX D

CHARACTERISTICS OF MAJOR POWDER RIVER BASIN COAL SEAMS

The sulfur and Btu contents of western, and in particular Powder River Basin, coals are significant for evaluating the impacts of alternative revised New Source Performance Standards. The sensitivity to these parameters is analyzed in the text and in Appendix C of this report.

Table D-1 lists the most important seams in the Powder River Basin and, for each seam, shows the sulfur, ash, and Btu content of the coal. Average sulfur content varies between approximately 0.4 percent and 0.6 percent, while the heating value may range from 7,500 to 9,500 Btu/lb; this is the equivalent of a range of 0.42 to 0.80 lb S/10^6 Btu. The ash content of Powder River coal varies from about 4 percent to 7 percent on the average.

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Table D-1

Characteristics of Major Powder River Basin Coal Seams

Seam	Sulfur (%)		Ash (%)		Btu/lb		lb $S/10^6$ Btu	
	Range	Average	Range	Average	Range	Average	Range	Average
Anderson	0.17 - 1.13	0.52	3.5 - 12.2	6.5	7,128 - 8,737	7,979	0.19 - 1.59	0.65
Badger	0.4 - 0.5	0.45	6.9 - 9.8	7.9	7,606 - 8,290	7,951	0.48 - 0.66	0.57
Canyon	0.14 - 0.92	0.34	3.1 - 7.4	5.1	7,537 - 8,609	8,286	0.16 - 1.22	0.41
Felix	0.32 - 3.26	0.89	4.5 - 14.9	7.8	7,180 - 9,535	8,053	0.34 - 4.54	1.11
Healy	0.26 - 3.0	0.6	5.1 - 22.1	7.6	6,480 - 8,270	7,884	0.31 - 4.63	0.76
Monarch	0.3 - 0.7	0.4	3.1 - 8.2	4.4	9,000 - 10,410	9,600	0.29 - 0.78	0.42
School	0.5 - 0.7	0.6	8.8 - 15.7	11.4	7,830 - 8,870	8,183	0.56 - 0.89	0.73
Smith		0.63		4.7		7,991		0.79
Sussex		0.49		5.2		9,160		0.53
Wodak-Anderson	0.2 - 1.2	0.5	3.9 - 12.2	6.0	7,420 - 9,600	8,224	0.21 - 1.62	0.61

Source: *Keystone Coal Industry Manual*, 1977, pp. 711-13.

APPENDIX E

PROJECTED REGIONAL AND NATIONAL UTILITY COAL PRODUCTION

APPENDIX E

PROJECTED REGIONAL AND NATIONAL UTILITY COAL PRODUCTION

Tables

E1 – E3	Regional Utility Coal Production: 1985, 1990, 1995 (scrubber cost estimates by PEDCo)
E4	Summary of Regional Growth Rates in Utility Coal Production, 1985-1995 (scrubber cost estimates by PEDCo)
E5 – E7	Regional Utility Coal Production: 1985, 1990, 1995 (scrubber cost estimates by TVA)
E8	Summary of Regional Growth Rates in Utility Coal Production, 1985-1995 (scrubber cost estimates by TVA)

Region Definitions

Appalachia = Ohio, Pennsylvania, West Virginia, Virginia, Kentucky (east), Tennessee, Alabama

Midwest = Illinois, Indiana, Kentucky (west), Iowa, Missouri, Kansas, Oklahoma

Northern Great Plains = Montana, Wyoming (north), North Dakota, South Dakota

Rocky Mountain = Wyoming (south), Colorado, Utah, Arizona, New Mexico

Gulf Coast = Texas, Arkansas, Louisiana

Other = Washington, Oregon, Nevada, California

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Table E-1

Regional Utility Coal Production: 1985*
(10^6 tons per year)

Region	Current NSPS	0.6 lb Floor	0.2 lb Floor	0.6 lb Ceiling
Appalachia	322.2	321.9	342.7	335.6
Midwest	79.7	82.7	82.6	81.1
Northern Great Plains	213.4	206.1	170.0	182.5
Rocky Mountain	102.4	103.6	95.4	103.5
Gulf Coast	17.0	22.7	42.3	27.6
Other	2.8	2.8	2.8	2.8
National	737.5	739.8	735.8	733.1
Western coal shipped east of the Mississippi River	110.7	109.5	79.2	89.8

*Scrubber cost estimates by PEDCo.

Table E-2

Regional Utility Coal Production: 1990*
(10^6 tons per year)

Region	Current NSPS	0.6 lb Floor	0.2 lb Floor	0.6 lb Ceiling
Appalachia	382.2	379.4	437.1	414.0
Midwest	73.6	81.0	81.0	78.3
Northern Great Plains	362.2	343.6	214.3	249.7
Rocky Mountain	150.3	160.3	107.4	154.7
Gulf Coast	17.0	23.1	168.2	77.9
Other	2.2	15.0	15.2	15.0
National	987.5	1002.4	1023.2	989.6
Western coal shipped east of the Mississippi River	179.0	167.5	79.3	111.5

*Scrubber cost estimates by PEDCo.

Table E-3

Regional Utility Coal Production: 1995*
(10^6 tons per year)

Region	Current NSPS	0.6 lb Floor	0.2 lb Floor	0.6 lb Ceiling
Appalachia	446.8	459.8	539.7	503.5
Midwest	68.4	79.6	79.6	79.5
Northern Great Plains	521.8	476.8	273.8	319.6
Rocky Mountain	193.0	206.2	133.1	200.9
Gulf Coast	17.0	24.3	260.4	120.1
Other	2.7	23.0	22.6	22.9
National	1249.7	1269.7	1309.2	1246.5
Western coal shipped east of the Mississippi River	239.5	216.6	92.9	136.2

*Scrubber cost estimates by PEDCo.

Table E-4

Summary of Regional Growth Rates in Utility Coal Production, 1985-1995*
(% per year)

Region	Current NSPS	0.6 lb Floor	0.2 lb Floor	0.6 lb Ceiling
Appalachia	3.3	3.6	4.5	4.1
Midwest	-1.5	-0.4	-0.4	-0.2
Northern Great Plains	8.9	8.4	4.8	5.6
Rocky Mountain	6.3	6.9	3.3	6.6
Gulf Coast	0.0	0.7	18.2	14.7
National	5.3	5.4	5.8	5.3
Western coal shipped east of the Mississippi River	7.7	6.8	1.6	4.2

*Scrubber cost estimates by PEDCo.

Table E-5

Regional Utility Coal Production: 1985*
(10^6 tons per year)

Region	Current NSPS	0.2 lb Floor	0.6 lb Ceiling
Appalachia	349.8	350.6	350.5
Midwest	79.5	83.3	81.7
Northern Great Plains	143.1	141.4	143.1
Rocky Mountain	62.3	62.4	62.4
Gulf Coast	96.1	92.3	92.3
Other	4.2	4.7	4.3
National	735.0	734.7	734.3
Western coal shipped east of the Mississippi River	58.0	56.2	58.0

*Scrubber cost estimates by TVA.

Table E-6

Regional Utility Coal Production: 1990*
(10^6 tons per year)

Region	Current NSPS	0.2 lb Floor	0.6 lb Ceiling
Appalachia	433.1	435.0	434.6
Midwest	72.5	90.3	74.4
Northern Great Plains	188.3	172.2	190.6
Rocky Mountain	71.2	70.7	70.5
Gulf Coast	209.4	205.6	203.9
Other	15.5	15.7	15.7
National	990.0	989.5	989.7
Western coal shipped east of the Mississippi River	61.0	40.5	60.1

*Scrubber cost estimates by TVA.

Table E-7

Regional Utility Coal Production: 1995*
(10^6 tons per year)

Region	Current NSPS	0.2 lb Floor	0.6 lb Ceiling
Appalachia	528.7	531.9	532.0
Midwest	66.8	101.2	73.9
Northern Great Plains	264.4	210.4	241.5
Rocky Mountain	87.2	90.1	89.3
Gulf Coast	286.5	285.7	286.0
Other	24.1	23.5	24.4
National	1257.7	1242.8	1247.1
Western coal shipped east of the Mississippi River	72.1	32.7	66.1

*Scrubber cost estimates by TVA. .

Table E-8

Summary of Regional Growth Rates in Utility Coal Production, 1985-1995*
(% per year)

Region	Current NSPS	0.2 lb Floor	0.6 lb Ceiling
Appalachia	4.1	4.2	4.2
Midwest	-1.7	1.9	-0.1
Northern Great Plains	6.1	4.0	5.2
Rocky Mountain	3.4	3.7	3.6
Gulf Coast	10.9	11.3	11.3
National	5.4	5.3	5.3
Western coal shipped east of the Mississippi River	2.2	-5.4	1.3

*Scrubber cost estimates by TVA.

APPENDIX F

SELECTED RESULTS FOR 1990 AND 1995

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APPENDIX F

SELECTED RESULTS FOR 1990 AND 1995

Tables

F-1—F-4	USM Emission Projections, 1990 and 1995 (PEDCo FGD Costs, TVA FGD Costs)
F-5—F-8	USM Cost Projections, 1990 and 1995 (PEDCo FGD Costs, TVA FGD Costs)
F-9—F-12	USM Fuel Impact Projections, 1990 and 1995 (PEDCo FGD Costs, TVA FGD Costs)

Region Definitions

Definitions for Emission Summary Tables

Northeast = New England (Maine, Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont)
Middle Atlantic (New York, New Jersey, Pennsylvania)

Southeast = South Atlantic (Delaware, Maryland/D.C., Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida)
East South Central (Kentucky, Tennessee, Mississippi, Alabama)

North Central = East North Central (Wisconsin, Michigan, Illinois, Indiana, Ohio)
West North Central (North Dakota, South Dakota, Nebraska, Kansas, Iowa, Missouri, Minnesota)

West South Central = Texas, Oklahoma, Arkansas, Louisiana

Mountain = Idaho, Montana, Wyoming, Nevada, Utah, Colorado, Arizona, New Mexico

Pacific = Washington, Oregon, California

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Definitions for Fuel Impact Tables

Appalachia = Ohio, Pennsylvania, West Virginia, Virginia, Kentucky (eastern), Tennessee, Alabama

Midwest = Illinois, Indiana, Kentucky (western), Iowa, Missouri, Kansas, Oklahoma

Northern Great Plains = Montana, Wyoming (northern), North Dakota, South Dakota

West = Wyoming (southern), Colorado, Utah, Arizona, New Mexico, Washington

Gulf Coast = Texas, Arkansas, Louisiana

Table F-1

USM Emission Projections, 1990
(PEDCo FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.6 lb Uniform Ceiling[c]	0.6 lb Floor[d]
Regional power-plant SO_2 emissions (10^6 tons)				
Northeast	1.96	1.75	1.85	1.79
Southeast	7.92	7.09	7.25	7.02
North Central	7.11	6.93	6.89	6.99
West South Central	2.67	1.75	2.08	1.80
Mountain	0.63	0.53	0.57	0.55
Pacific	0.49	0.29	0.40	0.34
Total	20.8	18.3	19.1	18.5
National SO_2 emissions from coal-fired plants (10^6 tons)				
SIP-regulated plants	13.58	13.91	13.65	13.92
NSPS-regulated plants	1.54	1.53	1.53	1.54
RNSPS-regulated plants	3.92	1.10	2.19	1.26
Coal consumption (10^{15} Btu/yr)	19.5	20.0	19.8	19.9
National average lb $SO_2/10^6$ Btu				
SIP-regulated plants	2.60	2.72	2.72	2.70
NSPS-regulated plants	1.20	1.20	1.20	1.20
RNSPS-regulated plants	1.20	0.30	0.60	0.35

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 33 percent removal, 0.6 lb ceiling, annual average.

[d] Equivalent to b, but with 0.6 lb $SO_2/10^6$ floor, 24-hour standard.

Table F-2

USM Emission Projections, 1990 (TVA FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.5 lb Ceiling, 90% Removal[c]	0.6 lb Uniform Ceiling[d]
Regional power-plant SO_2 emissions (10^6 tons)				
Northeast	1.86	1.76	1.69	1.73
Southeast	7.55	6.87	6.81	6.97
North Central	7.03	6.67	6.54	6.59
West South Central	2.72	1.87	1.72	2.05
Mountain	0.62	0.53	0.52	0.57
Pacific	0.49	0.32	0.30	0.40
Total	20.3	18.0	17.6	18.3
National SO_2 emissions from coal-fired plants (10^6 tons)				
SIP-regulated plants	12.83	12.93	13.12	12.84
NSPS-regulated plants	1.67	1.65	1.64	1.56
RNSPS-regulated plants	4.13	1.68	1.10	2.24
Coal consumption (10^{15} Btu/yr)	19.4	19.6	19.6	19.5
National average lb $SO_2/10^6$ Btu				
SIP-regulated plants	2.60	2.73	2.74	2.72
NSPS-regulated plants	1.20	1.20	1.20	1.20
RNSPS-regulated plants	1.20	0.46	0.30	0.60

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[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 90 percent removal, 0.5 lb ceiling, annual average.

[d] 33 percent removal, 0.6 lb ceiling, annual average.

Table F-3

USM Emission Projections, 1995
(PEDCo FGD Costs)

	Current NSPS (Baseline)	0.2 lb Floor[b]	0.6 lb Uniform Ceiling[c]	0.6 lb Floor[d]
Regional power-plant SO_2 emissions (10^6 tons)				
Northeast	2.11	1.69	1.82	1.68
Southeast	8.54	7.01	7.46	7.04
North Central	7.51	6.95	7.12	7.19
West South Central	3.19	1.78	2.29	1.85
Mountain	0.76	0.59	0.68	0.63
Pacific	0.66	0.30	0.51	0.38
Total	22.8	18.3	19.9	18.8
National SO_2 emissions from coal-fired plants (10^6 tons)				
SIP-regulated plants	13.13	13.45	13.06	13.67
NSPS-regulated plants	1.50	1.51	1.50	1.52
RNSPS-regulated plants	6.74	1.94	3.87	2.15
Coal consumption (10^{15} Btu/yr)	24.3	25.1	24.6	24.9
National average lb $SO_2/10^6$ Btu				
SIP-regulated plants	2.49	2.77	2.76	2.65
NSPS-regulated plants	1.20	1.20	1.20	1.20
RNSPS-regulated plants	1.20	0.29	0.60	0.35

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[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 33 percent removal, 0.6 lb ceiling, annual average.

[d] Equivalent to b, but with 0.6 lb $SO_2/10^6$ floor, 24-hour standard.

Table F-4

USM Emission Projections, 1995
(TVA FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.5 lb Ceiling 90% Removal[c]	0.6 lb Uniform Ceiling[d]
Regional power-plant SO_2 emissions (10^6 tons)				
Northeast	1.98	1.68	1.54	1.65
Southeast	8.01	6.82	6.59	7.01
North Central	7.35	6.36	6.04	6.63
West South Central	3.25	1.98	1.74	2.19
Mountain	0.75	0.60	0.58	0.58
Pacific	0.67	0.34	0.30	0.60
Total	22.0	17.8	16.8	18.7
National SO_2 emissions from coal-fired plants (10^6 tons)				
SIP-regulated plants	11.82	11.66	11.78	11.87
NSPS-regulated plants	1.64	1.64	1.66	1.44
RNSPS-regulated plants	7.13	3.07	2.00	3.98
Coal consumption (10^{15} Btu/yr)	24.1	24.4	24.4	24.3
National average lb $SO_2/10^6$ Btu				
SIP-regulated plants	2.50	2.78	2.75	2.75
NSPS-regulated plants	1.20	1.20	1.20	1.20
RNSPS-regulated plants	1.20	0.47	0.31	0.60

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 90 percent removal, 0.5 lb ceiling, annual average.

[d] 33 percent removal, 0.6 lb ceiling, annual average.

Table F-5

USM Cost Projections, 1990
(PEDCo FGD Costs)

	Current NSPS[a] (Baseline)	0.2 lb Floor[b]	0.6 lb Uniform Ceiling[c]	0.6 lb Floor[d]
Average monthly residential bill ($ 1975)	$ 46.36	$ 48.24	$ 47.46	$ 47.82
Present value of total utility expenditures (10^9 1975 $)	683.77	692.34	688.49	690.83
Cost of SO_2 reduction (1975 $/ton)	–	2,174	1,900	1,824

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 33 percent removal, 0.6 lb ceiling, annual average.

[d] Equivalent to b, but with 0.6 lb $SO_2/10^6$ floor, 24-hour standard.

Table F-6

USM Cost Projections, 1990
(TVA FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.5 lb Ceiling 90% Removal[c]	0.6 lb Uniform Ceiling[d]
Average monthly residential bill ($ 1975)	$ 44.98	$ 45.87	$ 46.02	$ 45.69
Present value of total utility expenditures (10^9 1975 $)	673.88	677.5	678.17	676.63
Cost of SO_2 reduction (1975 $/ton)	–	1,155	1,146	1,031

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 90 percent removal, 0.5 lb ceiling, annual average.

[d] 33 percent removal, 0.6 lb ceiling, annual average.

Table F-7

USM Cost Projections, 1995
(PEDCo FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.6 lb Uniform Ceiling[c]	0.6 lb Floor[d]
Average monthly residential bill (1975 $)	$ 54.68	$ 57.37 (4.9%)	$ 56.21 (2.8%)	$ 57.02 (4.2%)
Present value of total utility expenditures (10^9 1975 $)	819.17	832.37 (1.6%)	826.21 (0.8%)	830.4 (1.4%)
Cost of SO_2 reduction (1975 $/ton)	–	1,591	1,375	1,531
Pollution control investment[e] (1983-2000) (10^9 1975 $)	40.1	+41.7 (104%)	+27.4 (68%)	+28.9 (72%)

Note: Numbers in parentheses indicate percentage change from baseline.

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 33 percent removal, 0.6 lb ceiling, annual average.

[d] Equivalent to b, but with 0.6 lb $SO_2/10^6$ floor, 24-hour standard.

[e] Assumes wet scrubbing technologies.

Table F-8

USM Cost Projections, 1995
(TVA FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.5 lb Ceiling 90% Removal[c]	0.6 lb Uniform Ceiling[d]
Average monthly residential bill (1975 $/month)	$ 52.67	$ 53.99 (2.5%)	$ 54.61 (3.6%)	$ 53.75 (2.1%)
Present value of total utility expenditures (10^9 1975 $)	805.07	811.0 (0.7%)	812.07 (0.9%)	809.73 (0.6%)
Cost of SO_2 reduction reduction (1975 $/ton)	–	900	831	900
Pollution control investment[e] (1983-2000) (10^9 1975 $)	33.9	+17.9 (53%)	+19.9 (59%)	+13.6 (40%)

Note: Numbers in parentheses indicate percentage change from baseline.

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 90 percent removal, 0.5 lb ceiling, annual average.

[d] 33 percent removal, 0.6 lb ceiling, annual average.

[e] Assumes wet scrubbing technologies.

Table F-9

USM Fuel Impact Projections, 1990
(PEDCo FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.6 lb Uniform Ceiling[c]	0.6 lb Floor[d]
Utility coal production by region (10^6 tons/yr)[e]				
Appalachia	382	437	414	379
Midwest	74	81	78	81
Northern Great Plains	362	214	250	344
West and Gulf Coast	167	275	233	183
National	988	1023	990	1003
Western coal shipped east of the Mississippi River (10^6 tons/yr)	167	79	112	168
Utility fossil fuel consumption				
Coal (10^{15} Btu/yr)	19.5	20.0	19.8	19.9
Oil (10^{15} Btu/yr)	3.95	3.95	3.90	3.90
(10^6 bbls/day)	1.78	1.79	1.76	1.76
Coal transportation (10^{15} Btu/yr)	0.26	0.185	0.205	0.261
Total fossil fuel consumption (10^{15} Btu)	23.8	24.2	23.9	24.1

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 33 percent removal, 0.6 lb ceiling, annual average.

[d] Equivalent to b, but with 0.6 lb $SO_2/10^6$ floor, 24-hour standard.

[e] Includes only coal produced for electric utility consumption.

Table F-10

USM Fuel Impact Projections, 1990
(TVA FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.5 lb Ceiling 90% Removal[c]	0.6 lb Uniform Ceiling[d]
Utility coal production by region (10^6 tons/yr)[e]				
Appalachia	433	435	435	436
Midwest	73	90	74	91
Northern Great Plains	197	172	191	172
West and Gulf Coast	269	276	274	277
National	987	990	990	991
Western coal shipped east of the Mississippi River (10^6 tons/yr))	61	41	60	41
Utility fossil fuel consumption				
Coal (10^{15} Btu/yr)	19.4	19.6	19.5	19.6
Oil (10^{15} Btu/yr)	3.84	3.90	3.91	3.90
(10^6 bbls/day)	1.73	1.76	1.76	1.76
Coal transportation (10^{15} Btu/yr)	0.163	0.159	0.160	0.160
Total fossil fuel consumption (10^{15} Btu)	23.4	23.6	23.6	23.6

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 90 percent removal, 0.5 lb ceiling, annual average.

[d] 33 percent removal, 0.6 lb ceiling, annual average.

[e] Includes only coal produced for electric utility consumption.

Table F-11

USM Fuel Impact Projections, 1995
(PEDCo FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.6 lb Uniform Ceiling[c]	0.6 lb Floor[d]
Utility coal production by region (10^6 tons/yr)[e]				
Appalachia	447	540	504	460
Midwest	68	80	80	80
Northern Great Plains	522	274	320	477
West and Gulf Coast	210	394	321	231
National	1250	1309	1247	1270
Western coal shipped east of the Mississippi River (10^6 tons/yr)	240	93	136	217
Utility fossil fuel consumption				
Coal (10^{15} Btu/yr)	24.3	25.1	24.6	24.9
Oil (10^{15} Btu/yr)	3.1	3.096	3.11	3.098
(10^6 bbls/day)	1.42	1.40	1.41	1.39
Coal transportation (10^{15} Btu/yr)	0.353	0.226	0.254	0.340
Total fossil fuel consumption (10^{15} Btu)	27.8	28.4	28.0	28.3

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 33 percent removal, 0.6 lb ceiling, annual average.

[d] Equivalent to b, but with 0.6 lb $SO_2/10^6$ floor, 24-hour standard.

[e] Includes only coal produced for electric utility consumption.

Table F-12

USM Fuel Impact Projections, 1995
(TVA FGD Costs)

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.5 lb Ceiling 90% Removal[c]	0.6 lb Uniform Ceiling[d]
Utility coal production by region (10^6 tons/yr)[e]				
Appalachia	529	532	532	533
Midwest	69	101	74	101
Northern Great Plains	255	210	242	211
West and Gulf Coast	362	376	375	378
National	1236	1243	1247	1247
Western coal shipped east of the Mississippi River (10^6 tons/yr)	72	33	66	33
Utility fossil fuel consumption				
Coal (10^{15} Btu/yr)	24.1	24.4	24.3	24.4
Oil (10^{15} Btu/yr)	3.08	3.09	3.07	3.09
(10^6 bbls/day)	1.39	1.4	1.39	1.40
Coal transportation (10^{15} Btu/yr)	0.197	0.195	0.194	0.196
Total fossil fuel consumption (10^{15} Btu)	27.2	27.5	27.4	27.5

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed standard: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 90 percent removal, 0.5 lb ceiling, annual average.

[d] 33 percent removal, 0.6 lb ceiling, annual average.

[e] Includes only coal produced for electric utility consumption.

APPENDIX G

INPUT ASSUMPTIONS FOR THE PHASE 3 ANALYSIS

APPENDIX G

INPUT ASSUMPTIONS FOR THE PHASE 3 ANALYSIS*

Electricity Peak and Average Growth Rates (%/yr)	
1975 - 1985	4.8
1985 - 1995	4.0
Nuclear Capacity (GW)	
1985	99
1990	165
1995	228
Oil Prices (1975$/bbl)	
1985	12.90
1990	16.40
1995	21.00
General Inflation Rate (GIR) (%/yr)	5.5
Coal Transportation Cost Escalation	1.8% + GIR 1975-1985, GIR 1985-1995
Coal-Mining Labor Cost Escalation	1% + GIR

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* Specified by the Joint EPA/DOE Working Group.[7]

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APPENDIX H

PROJECTED NATIONAL ELECTRIC GENERATING CAPABILITY AND ELECTRICITY GENERATION BY FUEL, 1976-2000

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APPENDIX H

PROJECTED NATIONAL ELECTRIC GENERATING CAPABILITY AND ELECTRICITY GENERATION BY FUEL, 1976-2000

Figure H-1	Projected National Electric Generating Capability
Figure H-2	Projected National Electricity Generation by Fuel
Table H-1	Projected National Generating Capacity

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Figure H-1
Utility Simulation Model
Projected National Electric Generating Capability

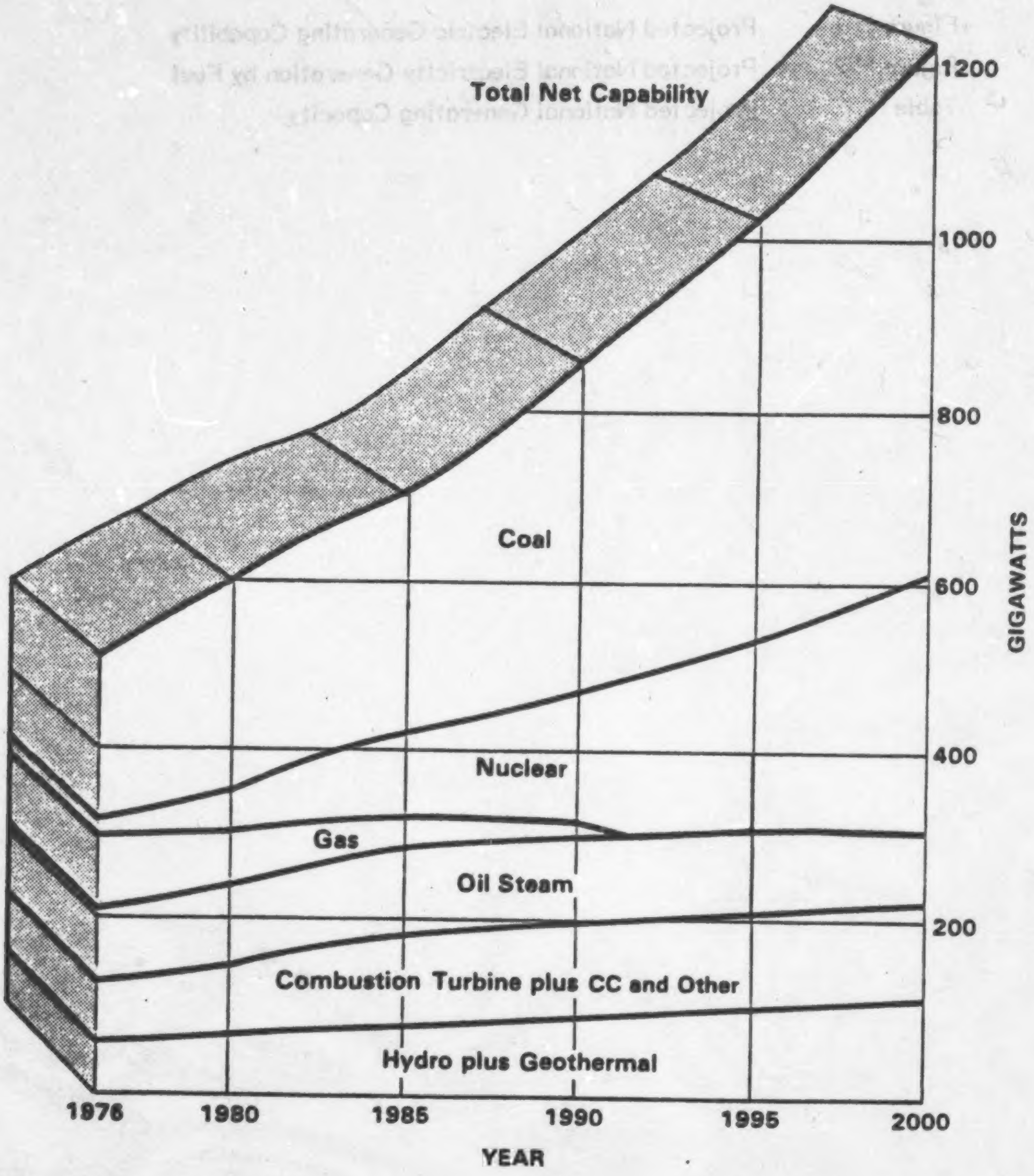

Figure H-2
Utility Simulation Model
Projected National Electricity Generation

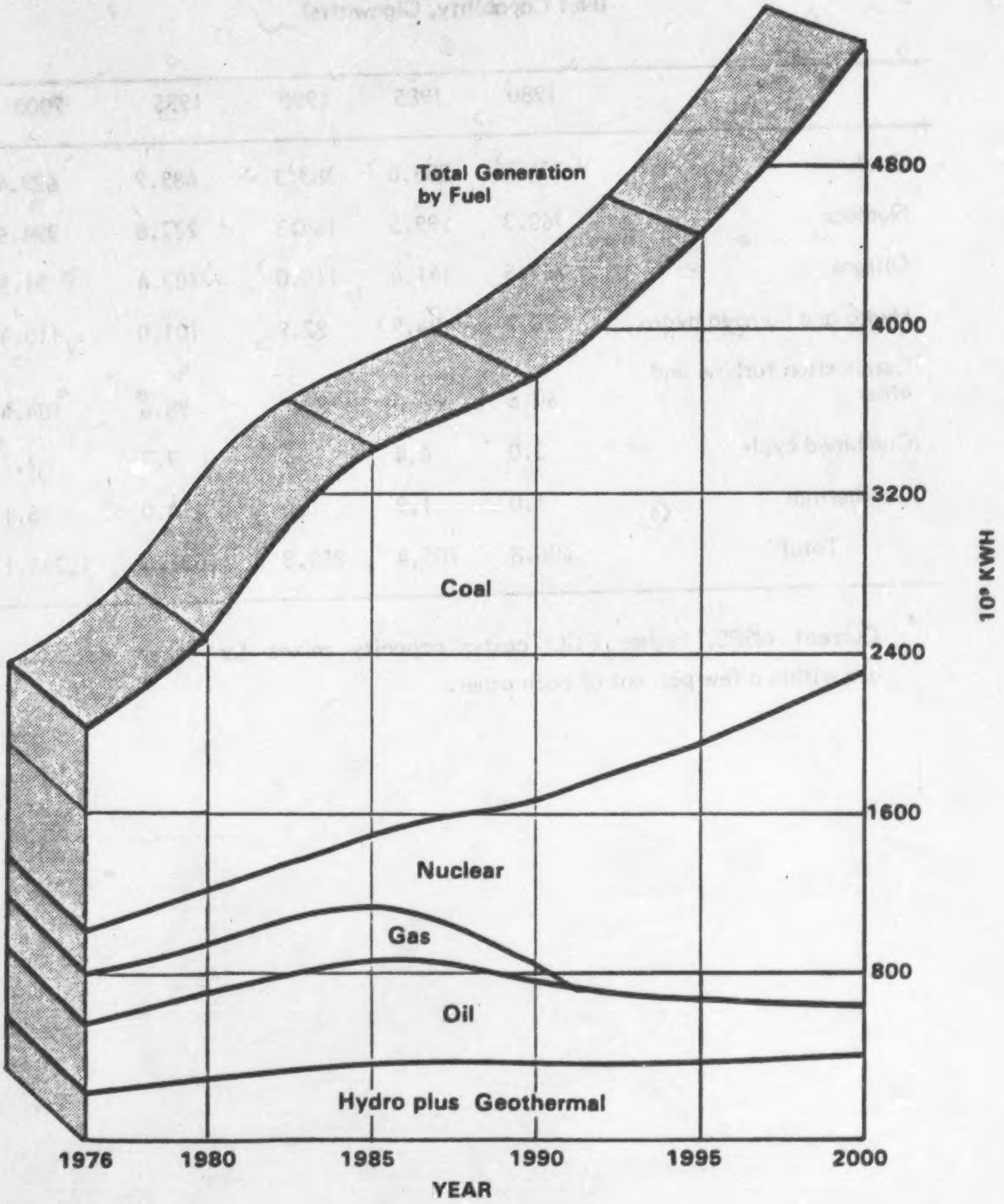

Table H-1

Projected National Generating Capacity

(Net Capability, Gigawatts)

	1980	1985	1990	1995	2000
Coal	234.4	283.0	383.3	489.9	629.4
Nuclear	60.3	99.5	164.3	227.8	294.6
Oil/gas	162.5	141.4	114.0	103.4	91.5
Hydro and pumped hydro	78.2	84.9	92.9	101.0	110.4
Combustion turbine and other	67.5	88.3	93.6	98.6	104.4
Combined cycle	3.0	6.4	7.7	7.7	7.7
Geothermal	1.0	1.9	3.0	4.0	5.1
Total	606.8	705.4	858.8	1,032.4	1,243.1

* Current NSPS, higher FGD costs; capacity mixes for other scenarios are within a few percent of each other.

APPENDIX I

USM PROJECTIONS FOR 1995 UNDER THE FINAL PROMULGATED RNSPS

APPENDIX I

USM PROJECTIONS FOR 1995 UNDER THE FINAL PROMULGATED RNSPS

On May 25, 1979 the EPA Administrator announced the final revised New Source Performance Standards for electric utilities. This appendix briefly compares the final standard with two potential RNSPS options investigated in this report. This comparison is followed by an EPA description of the final standard.

Projected Impacts of the Final RNSPS

There are two principal changes between our Phase 3 projections and our projection of the implications of the final RNSPS.

1. The definition of the final RNSPS. For coal plants "SO_2 emissions to the atmosphere are limited to 1.20 lb SO_2/million Btu heat input, and a 90 percent reduction in potential SO_2 emissions is required at all times except when emissions to the atmosphere are less than 0.60 lb SO_2/million Btu heat input. When SO_2 emissions are less than 0.60 lb SO_2/million Btu heat input, a 70 percent reduction in potential emissions is required. Compliance is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average."*

   As can be seen from Table I-1 in the text, the final RNSPS is less stringent than the September 1978 proposed full scrubbing option, but is more stringent than the potential RNSPS with a 0.6 lb $SO_2/10^6$ Btu uniform ceiling requiring 33 percent removal.

2. The use of dry scrubbing for FGD. Dry scrubbing technologies are an important element of the final RNSPS. For lower-sulfur coals dry scrubbing technologies should be less expensive than wet scrubbing processes. A new cost and performance model for dry scrubbing was developed in order to analyze the final RNSPS and to carry out comparisons with lime, limestone, and magnesium-oxide wet scrubbing technologies.

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* EPA Summary of Standards (Fact Sheet), May 25, 1979.

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Table I-1 presents Utility Simulation Model projections for 1995 under the final promulgated RNSPS.

Because dry scrubbing technologies were not assumed for the Phase 3 analyses, the projections for the final RNSPS are not strictly comparable to the Phase 3 projections. With this caveat, Tables I-2 and I-3 present a general comparison of the projected impacts of the final RNSPS and the two RNSPS options contrasted at the end of Section 2.

The following observations are pertinent:

- National SO_2 emissions are higher under the final RNSPS than under the September 1978 proposed RNSPS, which required 90 percent annual removal on all coals. This is principally due to the lower 70 percent removal requirement under the final RNSPS, which applies to low-sulfur coals with less than about 0.9 lb $S/10^6$ Btu. These coals will predominantly be used in the western U.S. Emissions under the final RNSPS will be lower than those projected under the 0.6 lb $SO_2/10^6$ Btu uniform ceiling partial scrubbing option and will be substantially lower than under a continuation of the current NSPS.

- Dry scrubbers would also be cheaper in many cases for meeting SIP standards. The extent to which dry scrubbing can be used at all on SIP-regulated plants will depend on SIP compliance schedules, and the availability and acceptance of dry scrubbing.

- The lower cost of dry scrubbers is reflected in cumulative Pollution Control Investment, which is estimated to be \$48 billion (1975\$) from 1983-2000. The corresponding investments for Phase 3 results using solely wet scrubbing are:

  \$40 billion under the current NSPS

  \$82 billion under the September 1978 proposed RNSPS

  \$67 billion under the 0.6 uniform ceiling with 33 percent removal.

  These pollution control investment figures include all pollution controls. PEDCo FGD costs were used for wet scrubbing; EPA costs for dry scrubbing.

- The lower cost of dry scrubbers results in lower levels of projected Eastern and Gulf Coast coal production relative to the wet scrubbing scenarios. Correspondingly, Northern Great Plains production increases. This occurs because low-sulfur Western coals will comply with the RNSPS at 70 percent removal using dry FGD technologies, increasing the attractiveness of these low-sulfur coals.

- The average monthly electricity bill is lower under the promulgated standard than for any alternative RNSPS analyzed using only wet scrubbing and PEDCo FGD costs. For example, under the September 1978 proposed standard the national average monthly electricity bill in 1995 was projected to be $57.37; under the final RNSPS it is $55.06.

The remainder of this Appendix quotes the EPA "Summary of Standards" released upon the announcement of the final revised NSPS, May 25, 1979.

SUMMARY OF STANDARDS

Applicability

The standards apply to electric utility steam generating units capable of firing more than 250 million Btu/hour heat input of fossil-fuel, for which construction is commenced after September 18, 1978.

SO_2 Standards

The SO_2 standards are as follows:

1. Solid and solid-derived fuels (except solid solvent refined coal): SO_2 emissions to the atmosphere are limited to 1.20 lb/million Btu heat input , and a 90 percent reduction in potential SO_2 emissions is required at all times except when emissions to the atmosphere are less than 0.60 lb/million Btu heat input. When SO_2 emissions are less than 0.60 lb/million Btu heat input, a 70 percent reduction in potential emissions is required. Compliance is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.

Table I-1

USM Projections for 1995 under the Final Promulgated RNSPS

National SO_2 Emissions (10^6 tons)	
Coal	
SIP	14.2
NSPS	1.3
RNSPS	2.9
Oil	1.2
Total (including turbines)	19.7
Regional SO_2 Emissions from All Power Plants (10^6 tons)	
New England	0.22
Mid Atlantic	1.28
South Atlantic	4.29
East North Central	5.00
West North Central	2.22
East South Central	3.46
West South Central	2.14
North Mountain	0.20
South Mountain	0.47
Pacific	0.46
Cumulative Total Utility Investment, 1983 onward in Billions of 1975$	566.5
Cumulative Pollution Control Investment, 1983 onward in Billions of 1975$	47.9
Present Value of Total Utility Costs Billions of 1975$	815.5
National Average Household Monthly Electricity Bill (1975$)	55.06
Utility Coal Production (10^6 tons)	
Appalachia	441.8
Midwest	87.8
Gulf Coast	74.0
Northern Great Plains	431.6
Rocky Mountains	164.9
Other	22.7
National	1,222.8
Western Coal Shipped East of Mississippi River (10^6 tons)	192

Table I-1 (Continued)

Annual Oil Consumption (10^{15} Btu)	3.1
(10^6 bbl/day)	1.51
Scrubber Capacities (GW)	
New England	2.8
Mid Atlantic	46.1
South Atlantic	56.3
East North Central	67.9
West North Central	22.7
East South Central	21.8
West South Central	78.1
North Mountain	5.2
South Mountain	19.6
Pacific	19.1
Total	339.6
Total SIP	56.0
Total NSPS	24.6
Total RNSPS	259.0
Total Coal Capacity (GW)	492.9
Total Nuclear Capacity (GW)	228.0
Total Oil Steam Capacity (GW)	103.4
Total System Size (GW)	1,030.5
Total Generation (10^9 kWh)	4,469.8

Definition of Regions for Emission Summary Tables

East = New England (ME, CT, RI, MA, NH, VT),
Middle Atlantic (NY, NJ, PA), and
South Atlantic (DE, MD/DC, VA, WV, NC, SC, GA, FL)

Midwest = East North Central (WI, MI, IL, IN, OH),
East South Central (KY, TN, MS, AL), and
West North Central (ND, SD, NE, KS, IA, MO, MN)

West South Central = West South Central (TX, OK, AR, LA)

West = Mountain (ID, MT, WY, NV, UT, CO, AZ, NM), and
Pacific (WA, OR, CA).

Table I-2

Utility Simulation Model Emission Impact Projections, 1995

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.6 lb Uniform Ceiling[c]	May 1979 Promulgated RNSPS[d]
Regional power-plant SO_2 emissions (10^6 tons)				
East	7.17	5.83	6.28	5.79
Midwest	10.99	9.82	10.12	10.68
West South Central	3.19	1.78	2.29	2.14
West	1.41	0.89	1.19	1.12
Total	22.8	18.3	19.9	19.7
National SO_2 emissions from coal-fired plants (10^6 tons)				
SIP-regulated plants	13.13	13.45	13.06	14.2
NSPS-regulated plants	1.50	1.51	1.50	1.31
RNSPS-regulated plants	6.74	1.94	3.87	2.85
Coal consumption (10^{15} Btu/yr)	24.3	25.1	24.6	24.4
National average lb $SO_2/10^6$ Btu				
SIP-regulated plants	2.49	2.77	2.76	2.80
NSPS-regulated plants	1.20	1.20	1.20	1.20
RNSPS-regulated plants	1.20	0.29	0.60	0.47

[a] Current NSPS: 1.2 lb $SO_2 10^6$/Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed RNSPS: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 33 percent removal, 0.6 lb ceiling, annual average.

[d] The May 1979 promulgated RNSPS projection utilizes dry scrubbing technologies as well as wet. Hence, the results are not strictly comparable to the other RNSPS projections which assumed only wet scrubbing processes.

Table I-3

Utility Simulation Model Cost Projections, 1995

	Current NSPS (Baseline)[a]	0.2 lb Floor[b]	0.6 lb Uniform Ceiling[c]	May 1979 Promulgated RNSPS[d]
Average monthly residential bill (1975 $)	$ 54.68	$ 57.37 (4.9%)	$ 56.21 (2.8%)	$ 55.06
Present value of total utility expenditures (10^9 1975 $)	819.17	832.37 (1.6%)	826.21 (0.8%)	815.5
Cost of SO_2 reduction (1975 $/ton)	–	1,591	1,375	–
Pollution control investment (1983-2000) (10^9 1975 $)	40.1	81.7	67.5	47.9

Note: Numbers in parentheses indicate percentage change from baseline.

[a] Current NSPS: 1.2 lb $SO_2/10^6$ Btu, no mandatory percentage removal, annual average.

[b] September 1978 proposed RNSPS: 1.2 lb $SO_2/10^6$ Btu, 85 percent SO_2 removal, 24-hour average; 0.2 lb $SO_2/10^6$ floor with three-day-per-month exemption.

[c] 33 percent removal, 0.6 lb ceiling, annual average.

[d] The May 1979 promulgated RNSPS projection utilizes dry scrubbing technologies as well as wet. Hence, the results are not strictly comparable to the other RNSPS projections which assumed only wet scrubbing processes.

2. Gaseous and liquid fuels not derived from solid fuels: SO_2 emissions into the atmosphere are limited to 0.80 lb/million Btu heat input, and a 90 percent reduction in potential SO_2 emissions is required. The percent reduction requirement does not apply if SO_2 emissions into the atmosphere are less than 0.20 lb/million Btu heat input. Compliance is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.

3. Anthracite coal: electric utility steam generating units firing anthracite coal alone are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the 1.20 lb/million Btu heat input emission limit on a 30-day rolling average, and all other provisions of the regulations including the pariculate matter and NO_x standards.

4. Noncontinental areas: Electric utility steam generating units located in noncontinental areas (State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Mariana Islands) are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the applicable SO_2 emission limitation and all other provisions of the regulations including the particulate matter and NO_x standards.

5. Resource recovery facilities: Resource recovery facilities that fire less than 25 percent fossil-fuel on a quarterly (90-day) heat input basis are not subject to the percentage reduction requirements but are subject to the 1.20 lb/million Btu heat input emission limit. Compliance is determined on a continuous basis using continuous monitoring to obtain a 30-day rolling average.

Particulate Matter Standards

The particulate matter standard limits emissions to 0.03 lb/million Btu heat input. The opacity standard limits the opacity of emissions to 20 percent (6-minute average).

NO_x Standards

The NO_x standards limit emissions according to fuel types as follows:

1. 0.20 lb/million Btu heat input from the combustion of any gaseous fuel, except gaseous fuel derived from coal;
2. 0.30 lb/million Btu heat input from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;
3. 0.50 lb/million Btu heat input from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;
4. 0.80 lb/million Btu heat input from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;
5. Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from the NO_x standards and monitoring requirements; and
6. 0.60 lb/million Btu heat input from the combustion of any solid fuel not specified under (3), (4), or (5).

Continuous compliance with the NO_x standards is required, based on a 30-day rolling average.

Emerging Technologies

The standards include provisions which allow the Administrator to grant commercial demonstration permits to allow less stringent requirements for the initial full-scale demonstration plants of certain technologies. The standards include the following provisions:

1. Facilities using SRC I would be subject to an emission limitation of 1.20 lb/million Btu heat input, based on a 30-day rolling average, and an emission reduction requirement of 85 percent, based on a 24-hour average.

However, the percentage reduction allowed under a commercial demonstration permit for the initial full-scale demonstration plants using SRC I would be 80 percent (based on a 24-hour average). The plant producing the SRC I would monitor to insure that the required percentage reduction (24-hour average) is achieved and the power plant using the SRC I would monitor to ensure that the 1.20 lb/million Btu heat input limit (30-day rolling average) is achieved.

2. Facilities using fluidized bed combustion (FBC) and coal liquefaction would be subject to the emission limitation and percentage reduction requirement of the SO_2 standard and to the particulate matter and NO_x standards. However, the reduction in potential SO_2 emissions allowed under a commercial demonstration permit for the initial full-scale demonstration plants using FBC would be 85 percent (based on a 30-day rolling average). The NO_x emission limitation allowed under a commercial demonstration permit for the initial full-scale demonstration plants using coal liquefaction would be 0.70 lb/million Btu heat input, based on a 30-day rolling average.

3. No more than 15,000 MW equivalent electrical capacity would be allotted for the purpose of commerical demonstration permits. The capacity will be allocated as follows:

Technology	Pollutant	Equivalent Electrical Capacity MW
Solid solvent-refined coal	SO_2	5,000 - 10,000
Fluidized bed combustion (atmospheric)	SO_2	400 - 3,000
Fluidized bed combustion (pressurized)	SO_2	200 - 1,200
Coal liquefaction	NO_x	750 - 10,000

SO_2 Standard

- Standard is based on the performance of well designed, operated, and maintained wet lime/limestone SO_2 scrubbing system.

- The minimum requirement of 70 percent removal provides an opportunity for the full development of dry SO_2 removal systems.

- Sulfur removed through coal washing or in the fly ash and bottom ash is also credited toward achievement of the standard.

- Lime/limestone wet scrubbing is capable of 90 percent SO_2 reduction on all coals and up to 95 percent SO_2 reduction on low-sulfur coals.

- Regenerable wet scrubbing, which is capable of higher percent SO_2 reductions at added cost, has also been demonstrated and is applicable where limited land area is available for sludge disposal.

- Several wet scrubbing systems have demonstrated high percentages of SO_2 reduction. These are:

Unit	Size (MW)	Type	Location	Percent Reduction
1. Columbus & So. Ohio Conesville Station	400	Lime	U.S.A.	89.2
2. No. Indiana Publ. Serv. Mitchell Station	115	Regen.	U.S.A.	89.2
3. Tennessee Val. Auth. Shawnee Station	10	Lime	U.S.A.	88.6
4. Kansas Power & Light Lawrence Station	125	Limestone	U.S.A.	96.6
5. Louisville Gas & Elec. Cane Run Station	178	Lime	U.S.A.	89.8
6. Arizona Publ. Serv. Cholla Station	115	Limestone	U.S.A.	92
7. Southern California Ed. Mohave Station	170	Limestone	U.S.A.	95
8. Pennsylvania Power Bruce Mansfield Station	800	Limestone	U.S.A.	85.3
9. Elec. Power Devel. Takasago Station	500	Limestone	Japan	93
10. Elec. Power Devel. Isogo Station	530	Limestone	Japan	93

	Unit	Size (MW)	Type	Location	Percent Reduction
11.	Elec. Power Devel. Takehara Station	256	Limestone	Japan	93
12.	Mitsui Aluminum Miiki Station	175	Limestone	Japan	90

- Water and solid waste products of wet scrubbing can be managed in an environmentally sound manner.
- Dry scrubbing is considerably less complex than lime/limestone wet scrubbing systems.
- Dry scrubbing involves contacting SO_2-laden flue gas with an alkaline solution in a spray dryer which simultaneously drys the liquid and allows absorption of the SO_2 by the alkaline reagent. The dry solid reaction product, along with fly ash, is collected in a conventional baghouse or electrostatic precipitator.
- Five commercial dry SO_2 control systems are on order; three for utility boilers and two for industrial applications. The utility units will commence operation in the 1981-1982 time frame.
- The utility boilers are:

	Unit	Size (MW)	Percent Reduction
1.	Otter Trail Power Coyote #1, N.D.	400	50
2.	Basin Electric Laramie River #1, Wyoming	550	85
3.	Basin Electric Antelope Valley #1, N.D.	455	70

- All utility units are on low-sulfur high-alkaline coal.
- The industrial applications are:

	Unit	Size (SCFM)	Percent Reduction
1.	Celanese Corporation Cumberland Plant, Md.	57,700	70
2.	Struthmore Paper Company Woronoco Plant, Mass.	22,000	N/A

- Successful testing of the spray dryer process at the pilot scale has been performed. The data suggest that at a 70 percent sulfur removal requirement, dry systems offer major cost advantages over lime/limestone wet scrubbers for low-sulfur coal applications.

- Annual revenue requirements are estimated at one-third less than corresponding wet lime scrubbing assuming a subbituminous (0.7 percent sulfur) coal and a 70 percent control requirement.

- Dry and wet costs are approximately equal for a 2 percent sulfur coal.

- Other benefits:

  - Reduction in consumptive water use

  - Potential for higher reliability due to simpler process

  - Substantial reduction in energy losses since reheat requirement is eliminated

  - Production of a dry solid waste material. Although larger in quantity, it can be more easily disposed of than wet scrubber sludge

Particulate Matter Standard

- Standard is based on performance of well designed, operated, and maintained electrostatic precipitator (ESP) or baghouse control systems.

- ESPs were initially installed by the utility industry in the 1920s, with widespread use since the 1950s.

- ESPs with sufficient collection area can achieve the standard on both high- and low-sulfur coal applications.

- On Western, low-sulfur coal applications, however, ESPs must be much larger due to the electrical resistivity of the fly ash, making the equipment more expensive.

- Baghouses (fabric filters), which are relatively new to utility applications, offer a lower cost alternative to ESPs on Western, low-sulfur coals.

- Baghouses, however, are not new to large industrial and boiler applications. They have been used in industrial applications for more than 20 years.

- To date, most baghouses have been installed on small stations, but this is changing rapidly as utilities order baghouses for larger installations.

- Since proposal, a 350-MW unit equipped with a baghouse has started operation and test results show that it meets the new standard.

NO_x Standards

- The NO_x standards can be achieved with the use of combustion modification. This technique reduces the formation of nitrogen oxide gases in the furnace where the fuel is burned. No external control device, such as a stack-gas scrubber, is required.

- In developing the NO_x standards, EPA tested six well-controlled electric utility power plants. Two of the plants burned Eastern bituminous coal, one burned Western bituminous coal, and three burned Western subbituminous coal. All of the plants had NO_x emission levels below the new standards.

- In addition to the EPA test data, boiler manufacturer and electric utility test data have been obtained for a number of coal-fired power plants, including 30 months of continuously monitored NO_x data. Virtually all of these data support the NO_x standards.

- Compliance with the NO_x standards is based on a 30-day rolling average of emission levels. This averaging period is intended to give boiler operators the flexibility they need to handle conditions which occur during the normal operation of an electric utility boiler. Some of the conditions, such as slagging, may require elevated NO_x emission levels over short periods of time. (Slagging reduces boiler efficiency and is caused by the accumulation of coal ash on the boiler tubes.)

- The NO_x standard for bituminous coal is higher than the NO_x standard for subbituminous coal due to concern over boiler tube corrosion when bituminous coal is burned during low-NO_x operation. The NO_x standard for bituminous coal represents an emission level at which an electric utility boiler can operate without increasing corrosion which can shorten the life of boiler tubes and cause expensive repairs.

GLOSSARY OF SO_2 STANDARDS TERMINOLOGY

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Averaging time	Period of time over which the emissions are averaged. Coal sulfur content is variable, and the maximum 24-hour emission is greater than the maximum 30-day emission, which makes a shorter averaging time a more stringent requirement.
Bypass	Flue gas that is not treated by the flue gas desulfurization (FGD) system. The bypass may be operated such that either a fixed or a variable percentage of the flue gas is bypassed. If the bypass is variable, it is assumed that it will be operated to minimize cost and maximize emissions.
Ceiling	An emission limit that is not to be exceeded except as specified.
Exemptions	Number of days per month the ceiling can be exceeded.
Floor	A limit that allows fuels of very low sulfur content (e.g., natural gas, distillate oil, biomass) to be burned without SO_2 controls. The floor also allows partial scrubbing of low-sulfur coals and bypassing of unscrubbed flue gas for reheating.
Required percentage removal	The percentage of the flue gas SO_2 that must be removed unless the ceiling or the floor controls. If the ceiling controls, a larger portion of the SO_2 must be removed; if the floor controls, a smaller portion may be removed.
RSD	Relative standard deviation. The RSD is equal to the standard deviation divided by the mean of a set of samples. For a normally distributed sample population, 95 percent of the samples would be within two standard deviations of the mean. With respect to coal sulfur content, 90 percent of the time (the equivalent of 27 days per month), it is assumed that the measured coal sulfur content would be within roughly ± 2 standard deviations of the mean. It is assumed that essentially all of the samples fall below three standard deviations

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